ONTARIO POWER AUTHORITY

4 Supply Mix Consulting Reports

Volume 4 – December 2005

Ontario Power Authority

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Supply Mix Consulting Reports

Volume 4 – December 2005

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NAVIGANT CONSULTING

OVERVIEW OF THE PORTFOLIO SCREENING MODEL

prepared for

THE ONTARIO POWER AUTHORITY

DECEMBER 2005

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1 INTRODUCTION

Navigant Consulting was retained to provide the modeling tools and data to be used in implementing a planning approach that could rapidly and flexibly assess the risks, environmental attributes and cost characteristics of various resource portfolios. The Navigant Consulting team worked closely with OPA staff to develop a model that could meet the needs of the OPA in analyzing these portfolios and formulating a recommendation to the Ministry of Energy.

There are three key elements or capabilities to any resource planning analysis model:

- Resource "Dispatch" Algorithms – resource includes thermal, renewable, hydro, CDM, anything that goes to ultimately "serve" load;
- Financial Analysis – representation of fixed and variable costs, capital structure, etc.
- Risk Analysis – ability to simulate multiple correlated variables in an integrated fashion, ability to model scenarios or sensitivities; and

However, when constructing any model, the following relationship always holds:

*Breadth * depth of capability is proportional to model size and run time*

In other words, if a model tries to do all things with a high level of precision, it will become too big to manage and take too long to produce any meaningful decision information. Given the short turnaround time available to the OPA to formulate their recommendation, the focus of this analysis was to develop a model with sufficient breadth and reasonable precision that would allow the OPA to rapidly test a variety of resource portfolios with confidence.

Navigant Consulting Inc. has developed The Portfolio Screening Model ("PSM") over a period of several years and has applied it for several clients in both public and confidential situations in the US since 2000. The PSM is an Excel-based resource analysis tool that employs a simple dispatch algorithm, a detailed financial representation, and a complex risk analysis capability to assess the attractiveness of various portfolios of supply and demand-side resources. This report will outline the model logic, data sources, external models and processes that Navigant Consulting used to develop the PSM and its key components including the load profiles, operating assumptions, financial analysis and risk analysis used in the model.

2 PORTFOLIO SCREENING MODEL

Navigant Consulting Inc. has developed The Portfolio Screening Model ("PSM") over a period of several years and has applied it for several clients in both public and confidential situations in the US since 2000. The PSM is an Excel-based resource analysis tool. The PSM employs a simple dispatch algorithm, a detailed financial representation, and a complex risk analysis capability to assess the attractiveness of various portfolios of supply and demand-side resources. This section of the report will provide a general discussion of resource planning analysis platforms, a description of the primary components and algorithms of the PSM, and the calibration/verification process employed for development purposes with the OPA.

2.1 PSM OVERVIEW

Analytical modelling for resource planning has its genesis in generation planning from as early as the 1950's. The period of the 1970's through the early 1990's saw widespread use of Integrated Resource Planning throughout North America. Many capacity expansion optimization software platforms were developed in this time frame, the most famous of which is the Electric Power Research Institute (EPRI) Electric Generation Expansion Analysis System (EGEAS) model. Several other models were developed for transmission planning and unit commitment modelling; e.g. ProMod, ProSym, Aurora, MIDAS and others. As the prospect for competitive markets took hold in North America in the late 1990's, utility commissions moved away from the integrated planning model with many embracing the merchant model. The collapse of the merchant model ushered in a new era of integrated resource planning in the US, but with a twist on the old "least cost" planning model. Risk had become a key decision variable in the process of Integrated Resource Planning.

Many of the unit commitment models, e.g. ProSym, had Monte Carlo logic integrated to allow probabilistic treatment of forced outages, however beyond that, there was no simulation capability. Other models, MIDAS most notably, contained decision tree logic which gave a rudimentary risk analysis capability for resource planning purposes, but without a robust statistical basis; variables were largely uncorrelated, and probabilities assigned to nodes were not directly tied to a continuous distribution.

As utilities returned to the integrated resource planning model in the early part of this decade, Navigant Consulting, Inc. (NCI) saw an opportunity to leverage its market and financial risk analysis tools for use in resource planning. With the advent of high speed computing on the desktop combined with commercially available sophisticated risk analysis software, NCI developed spreadsheet based unit commitment and financial models that integrated a very robust risk analysis capability through Monte Carlo simulation. In 2002, NCI combined its market and financial models with a portfolio screening logic. This became NCI's Portfolio Screening Model (PSM).

Since 2002, the Portfolio Screening Model has been used in public resource planning processes in the state of Washington with Puget Sound Energy, the state of New Mexico with PNM Resources, and for confidential clients in the states of Texas, Missouri, and Maryland. . In both the state of Washington and New Mexico, the PSM has been scrutinized by the respective public service Commissions and Commission Staffs. NCI has provided direct testimony and has been cross examined on the veracity of the results produced using the PSM, in each case, the PSM was successfully defended for use in resource planning decision making (although the PNM case is ongoing). In these proceedings, the PSM was validated against an independent model; the Puget case used Aurora and ProSym as the benchmarks for the PSM, while the PNM case utilized Strategist. For the Fuel Mix Analysis, NCI is utilizing ProSym (as described in Section 2.4 below).

The PSM as it is currently employed by the OPA, is comprised of three primary components; an assumptions/inputs module, a dispatch module, and a financial analysis/reporting module[1]. The remainder of this section of the report will detail dispatch and risk analysis logic contained in the PSM and will discuss the calibration/verification process employed.

2.2 DISPATCH LOGIC

The dispatch logic in the PSM is based on a chronological merit order dispatch to load within the Ontario market region. The dispatch logic is "simple" in that there are no constraints associated with the operation of individual units, e.g. ramp rates, minimum down/up time, variable load levels, etc. The dispatch is conducted on an hourly basis for a "typical week" for each month of the year. The typical week structure is common to several modelling platforms and collapses an entire month of load information into an average expected, or typical week for that month. This simplification reduces the dispatch hours per year in the model from 8,760 to 2,016 resulting in a factor of four increase in calculation speed and reduction in model size. The dispatch order is based on the variable cost associated with the dispatch of individual units or plants, e.g. fuel cost, variable O&M cost, etc.

There are two steps to the dispatch of resources in the PSM. The first component dispatches the "must run" resources, the second dispatches the "dispatchable" resources. Must run is a general term denoting resources that are not dispatched on the basis of their variable cost. Dispatchable resources are traditional thermal resources including nuclear, coal, gas, and oil resources. The resources considered must run in the PSM are as follows:

- Conservation and Demand Side Management (CDM)
- Intermittent resources – run of river hydro and wind

[1] For assumptions pertaining to the resources modelled, refer to Section 3 of this report. For assumptions pertaining to the load forecast, refer to Section 4 of this report. For assumptions pertaining to the risk analysis inputs, see Section 6 of this report. For details pertaining to the financial calculations in the PSM, see Section 5 of this report.

- Zero variable cost resources – dispatchable hydro
- Cogeneration or NUG facilities

The must run resources are aggregated for each hour of each typical week and dispatched against load first (before the dispatchable resources). Mathematically, this is equivalent to decrementing the load by an amount equal to the total available must run capacity in each hour. The dispatchable resources are then dispatched against the remaining load.

There are three primary data inputs to the dispatch logic; the load, the available capacity for dispatch, and the dispatch basis of the dispatchable resources. The development of the hourly load is detailed in Section 4 of this report. The available capacity is developed for both must run and dispatchable resources. The dispatch basis is developed for only the dispatchable resources.

The available capacity is developed using different levels of granularity with respect to time based on the resource type. All resources either have available capacity developed on an hourly or monthly basis. All Hydro resources, wind resources, and CDM resource have hourly available capacity profiles. Thermal units, both must run and dispatchable have monthly profiles. The hourly profiles for the hydro and wind resources are developed using the combination of a monthly profile and an hour-of-the-day profile applied to the capacity of the resource. The CDM profiles were developed by ICF, and the details of which are in the ICF consultants report.

The thermal units monthly available capacity is developed utilizing a combination of forced outage rate and planned outages applied to a nameplate capacity. Forced outage rates vary by unit and by technology. Forced outage rates may vary on an annual basis for each resource and decrement the nameplate capacity equally for all hours in each year. For example, if a 1,000 MW gas plant has a forced outage rate of 5% in a particular year, then its available capacity will be reduced by 50 MW for all hours in that year. Planned outages are input on a monthly basis as the percentage of time in that particular month the resource will be unavailable due to planned outage. Going back to the forced outage example, if the 1,000 MW gas plant has a planned outage equal to 50% of the hours in may, then its available capacity in may is 475 MW. The planned outage array for each resource can also be used to model other load decrements not associated with planned outages, e.g. seasonal variation, mothballing or retiring units, etc.

The dispatch basis of the dispatchable resources is developed on a monthly basis and is equal to the monthly fuel cost plus the annual average variable O&M. Fuel costs for all thermal units may be provided in a monthly profile. Natural gas and oil units have a monthly profile for their fuel costs. Coal and nuclear units have the same fuel in each month of a particular year, but the costs vary year to year.

The logic of the must run resource dispatch is very straightforward; in each hour of each year, the total available must run capacity is subtracted from the forecasted gross load. The logic

associated with the dispatch of the dispatchable resources against the remaining load is complex from a calculation perspective but relatively straightforward from a practical perspective. The dispatch done on a monthly basis for all years in the evaluation and then aggregated on an annual basis. The monthly breakdown of the dispatch is required to allow monthly profiles for the available capacity and the dispatch basis. The monthly breakdown also keeps the model size to within the limits of Excel (currently 128 MB).

For each month and for all years, the dispatch logic operates as follows. All dispatchable resources are ranked in merit order in each year based on the dispatch basis for that particular year (and month being dispatched). Using this ranking, a "stack" of cumulative available capacity is developed. For every hour, the net load (gross load minus all must run resources) is compared to this stack of cumulative resources so that the marginal resource can be determined. The marginal resource is defined as the resource at which the cumulative available capacity will serve the net load. Every resource in the stack below the marginal resource has its full available capacity dispatched. The marginal resource has only the amount of capacity necessary to meet the net load dispatched.

The dispatch of each dispatchable resource is aggregated to the monthly level. From this, capacity factors, total cost of dispatch, energy generated, and CO_2 emissions generated are developed for each resource. The energy generated is used in several of the environmental footprint metrics as well. For each hour, the marginal resource is tracked and retained. This allows the determination of the marginal fuel on a percentage of the year basis and also allows tracking of the "market clearing price" on an hourly basis. This is a proxy for what a competitive wholesale market price would be and is equal to the dispatch basis of the marginal resource. The market clearing price is also a key value used in validating the dispatch logic.

2.3 RISK ANALYSIS LOGIC

The risk analysis logic utilizes a widely used technique; applying stochastic multipliers to underlying forecasts. The stochastic multipliers are normalized to one so that they can be directly multiplied by the appropriate underlying assumption or forecast. For details on how the stochastic multipliers are developed, see Section 6 of this report. Once the multipliers are developed, they are input directly into multiplier tables in the PSM. This is important in that when multiple simulations are run on varying portfolios, the same multipliers will be used in each analysis, thereby eliminating any error or drift due to random draws.

The model user is able to define the number of iteration to run in the simulation analysis. An iteration is a draw from the probability distributions and represents a possible world state as defined by the parameters of the probability distributions. Currently, a total of 1,000 iterations are possible, as there are 1,000 draws stored in the PSM (this number can be increased with only minor modification to the model structure). When running a risk simulation, the PSM will cycle through the iteration table for the pre-defined number of iterations and for each iteration will use the following process:

1. Select multipliers for the appropriate iteration
2. Apply multipliers to appropriate assumptions and forecasts
3. Dispatch resources to meet load under the new world state defined by the iteration
4. Calculate financial, environmental, and market related outputs
5. Save desired outputs
6. Repeat

Once all of the iterations have been completed, the data saved in step 5 above can be analyzed using descriptive statistics. The PSM also allows the user to select any of the simulation variables to be on or off during the simulation. This feature allows development of risk contribution analyses. By isolating each simulation variable and totalling the risk associated with each, a proxy for the contribution to total risk can be developed.

2.4 CALIBRATION & VALIDATION USING PROSYM

In order to ensure that the PSM had been properly set up and more importantly, that the simplified dispatch logic of the PSM would not introduce material error into the Supply mix Analysis, a calibration & validation was performed using ProSym as a benchmark. Both the PSM and ProSym were given the same set of inputs and assumptions to be run for comparison purposes. The assumptions and inputs were NOT meant to be representative of a preferred portfolio, but were only meant to be consistent across both platforms so as to ensure material differences, if any, could be identified.

Since the calibration and verification was only meant to be applied to the dispatch logic, two primary comparison metrics were used; market clearing price and energy generated by various resources in the Ontario portfolio. Because ProSym has a far more sophisticated dispatch logic with operational constraints, uplift bidding behavior, and other more subtle nuances, we do not expect the results to exactly line up with the PSM results, but be reasonably similar. The following figure shows the market clearing price comparison.

Figure 1 - Market Clearing Price Comparison

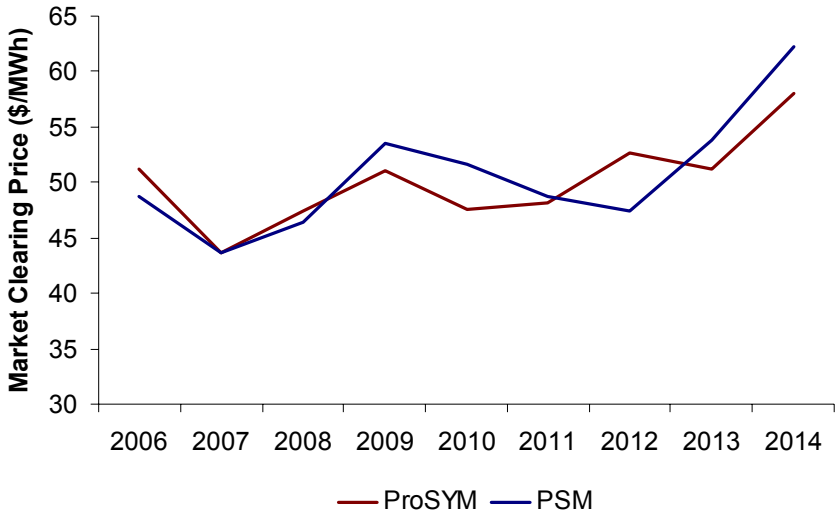


Figure 1 demonstrates that both the PSM and ProSym have similar units on the margin because the market clearing prices are also similar. Figure 2 shows the energy dispatched in 2006 for selected dispatchable resources.

Figure 2 – 2006 Energy Dispatched Comparison

			Delta	
	ProSym	PSM	MWh	%
Bruce	38,084	37,634	-449	-1.19%
Darlington	27,656	27,783	128	0.46%
Pickering	19,931	19,658	-273	-1.39%
Atikokan	1,521	1,650	129	7.82%
Lambton	11,108	9,193	-1,915	-20.83%
Nanticoke	22,534	25,487	2,954	11.59%
Thunder Bay	2,169	2,441	272	11.14%

Nanticoke comes before Lambton in the dispatch stack and should dispatch more often. The PSM does not include logic that would allow both units to run at reduced capacity. This is the source of the difference in dispatch rates. Since the dispatch basis of the two plants in this case are similar, the market clearing costs, and ultimately the revenue requirement will be very similar as well.

We made no changes to assumptions as a result of this validation.

3 RESOURCE ASSUMPTIONS

As outlined previously in this document, the PSM dispatch logic relies on a portfolio of resources that have been input by the user. At a granular level, these resources are defined as either:

- Existing Units – defined as units currently operating or anticipated in service prior to the period being analysed; or
- Forecast Unit Additions – defined as units under construction but not yet in service, or generic units to be added at some future date determined by the model user

All of these units, whether existing or new, will have assumptions for variable and fixed operating costs, capital costs for new units, heat rates and forced outage rates. These assumptions are usually identical for each type of generation technology[2] and can be changed by the user to conduct sensitivity analysis. Since most cost related assumptions, such as technology capital/operating cost and fuel prices are most frequently identified or traded in US dollars, all costs for the model are input in US dollars. After all calculations are performed, the PSM output is converted to a Canadian dollar equivalent based on the user's forecast exchange rate. The specific cost assumptions used for each technology are identified in the main report produced by the OPA.

In addition to defining the existing and new unit additions, the PSM also has separate schedules for unit retirements and major refurbishments. Each portfolio of new units can be accompanied by a unique schedule for retirements and refurbishments.

3.1 EXISTING UNITS

Assumptions for the existing fleet of generating units in Ontario was based on the same information used in the IESO 10 year outlook released in July 2005. Capacity for individual units cannot be identified in the report since it was provided to the IESO under strict confidentiality in accordance with section 25.13 of the Electricity Act, 1998. Total capacity by resource type is identified in the table below.

[2] The user can define multiple types of the same technology with different cost assumptions

Table 1 - Existing Resources

Resource Type	Capacity	%	Units
Nuclear	10,882	36%	5
Coal	6,434	21%	4
Oil/Gas	4,976	17%	20
Hydro	7,756	26%	67
Miscellaneous	66	0%	2
Total	30,114	100%	98

In addition to the existing units specified in the IESO study, the PSM includes 515MWs for Pickering A unit #1 which reconnected to the grid in November, subsequent to the release of the study.

3.2 New Units

There is essentially no limit to the number of new unit portfolios that the PSM can evaluate other than the maximum capacity of the Excel software (65,000 rows). Each portfolio is input into a matrix that describes the type and capacity of each unit as well as the year (2006 to 2025) in which the unit will commence operating. There are currently 65 rows available in each matrix to define the type and capacity of each unit and this matrix can be expanded if required. Each "X" in the matrix represents the year in which the unit will be placed in service and all new units are assumed to commence operating on January 1st. Each row in the matrix can be used multiple times to reflect identical units commencing operation at different times in the forecast period.

Figure 3 - Illustrative Portfolio Input

Resource	2006	2007	2008	2009	2010	2011	2012	2013	2014
Generic SCGT 250	-	-	-	X	-	-	-	-	-
Generic SCGT 100	-	X	-	-	-	-	-	-	-
Generic CCGT 500	-	-	X	-	-	-	-	-	-
Generic CCGT 1000	-	-	-	-	-	-	X	-	-
Generic Cogen 100	-	-	X	-	-	X	-	-	-
Generic Nuclear 1000	-	-	-	-	-	-	-	X	-
Generic Wind 100	X	-	-	-	-	-	-	-	-
Generic Wind 250	-	-	-	-	X	X	-	-	-
Generic Hydro 100	-	X	-	-	-	-	-	-	-
Generic Hydro 250	-	-	-	-	-	-	-	-	X

This in-service date will be used by the PSM to add new units to the dispatch logic as outlined in the previous section of this report. Based on the type and capacity of unit entering service, the PSM will increase the capital employed in the portfolio, annual fixed operating costs, and variable costs as determined by the dispatch of the unit during the year.

3.3 NUCLEAR AND COAL REFURBISHMENTS

Similar to the new unit input, the user is able to define a number of scenarios for major refurbishment of existing coal and nuclear units[3]. A specific nuclear refurbishment schedule has been developed for each portfolio of new resource additions. Nuclear refurbishments are assumed to encompass two years during which time the capacity of the nuclear plant is reduced to reflect the unit(s) that is off-line. Nuclear refurbishment capital costs are assumed to be $1.35 billion per unit and this capital expenditure is distributed evenly over the two year refurbishment period. This figure is based on the $2.7 billion that Bruce Power has forecast that it will spend to refurbish units 1 & 2 in the Bruce A generating station.

For the portfolio where the shut-down of Nanticoke is delayed and anticipated, it is assumed that some units of Nanticoke will be refurbished with scrubbers and selective catalytic reduction technology ("SCR"). Refurbishments are assumed to take one year during which time the capacity of Nanticoke is reduced to reflect the unit(s) that is off-line. Refurbishment capital costs are assumed to be $500 per kw or $205 million per unit. In addition, incremental operating costs associated with the cleaner emissions technology is assumed to add $5 per MWh to the variable operating cost.

3.4 RETIREMENTS OF EXISTING UNITS

Similar to the new unit input, the user is able to define a number of scenarios for retirements of existing units. Generating facilities can be retired all at once, or phased out over a number of years by unit(s). Individual unit retirements are assumed to occur on January 1st of the year in which the unit retires. The matrix used to record retirements shows accumulated capacity retired which is then subtracted from the total capacity available to dispatch during the year. An illustrative retirement matrix is shown below.

Table 2 - Illustrative Unit Retirement Matrix

Resource	2006	2007	2008	2009	2010	2011	2012
Existing Unit 1	-	-	211	211	211	211	211
Existing Unit 2	-	-	-	-	-	-	-
Existing Unit 3	-	-	970	970	970	970	970
Existing Unit 4	-	-	1,002	1,002	1,002	1,002	1,002
Existing Unit 5	-	-	-	-	-	-	-
Existing Unit 6	-	-	-	2,466	3,965	3,965	3,965
Existing Unit 7	-	-	-	-	516	516	1,547

[3] This schedule applies to extensive refurbishments that would require significant capital expenditure and the unit would be out of service for an extended period. Normal maintenance is covered under planned outage assumptions.

3.5 FUEL PRICE FORECASTS

Natural Gas Supply

The North American natural gas market is facing a decline in deliverability from existing natural gas production sources as they struggle to maintain current production levels. Meanwhile, since 1999, the US has added over 225 GW of natural gas-fired generation, representing almost one-third of US peak demand. With the significant amount of natural gas-fired capacity added, much of it is operating at relatively low capacity factors thus understating the potential demand that these electricity resources may place on natural gas supplies. As electricity demand grows, fuel requirements for this generating capacity will grow significantly. For example, a 2% increase in capacity factors for this new natural gas-fired generation would result in more than 1% increase in overall natural gas demand, which is forecast to grow by about 1.3% per year through 2010, with the utility sector accounting for the vast majority of demand growth . Therefore, unanticipated increases in demand from severe weather could result in significant run-ups in the price of natural gas

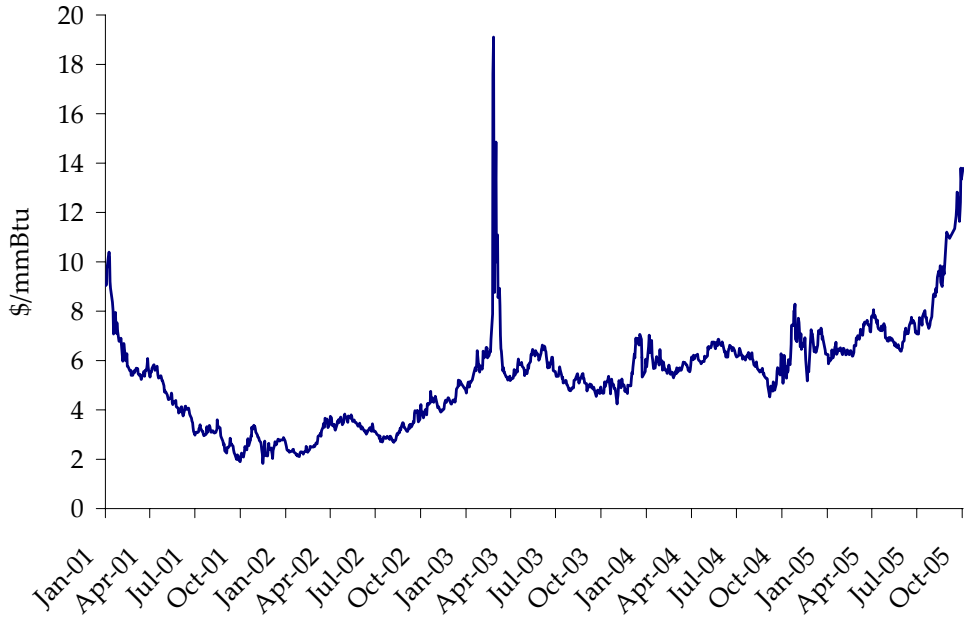
Under these market conditions, Liquefied Natural Gas (LNG) is expected to play a critical role in addressing the forecast supply gap. In a recent natural gas price forecast contained in an American Gas Association study (*Natural Gas Outlook to 2020: The U.S. Natural Gas Market-Outlook and Options for the Future)* LNG supplies accounted for over 50% of the additional gas supply (4,300 Bcf) required for 2015. Based on the average throughput of proposed LNG terminals, this would require the development of 10 new LNG terminals which would be a major undertaking given that permitting these facilities is difficult in the U.S. Limited LNG liquefaction infrastructure also appears to be constraining project development efforts and requiring LNG terminal developers to line up suppliers. With LNG as the swing supply, North American natural gas prices will be dictated by World energy markets, where demand is forecast to grow at 3% per year. Clearly, future natural gas prices will be significantly influenced by LNG project development and this represents a major long-term gas price risk.

While Ontario's natural gas market is well integrated into the broader North American market, some of the most advanced new LNG projects are in Canada. There are five projects in Eastern Canada and 2 in British Columbia (ranging from 300 MMcfd to 1 Bcfd with an average of 700 MMcfd):

- Rabaska (near Levi, Québec) - Joint Venture of GazMetro, Enbridge and Gaz de France
- Saint John (New Brunswick) - Joint Venture with Irving and Chevron
- Bear Head (Strait of Canso, Nova Scotia) - Access Northeast Energy
- Goldboro (Nova Scotia) – Keltic Petrochemicals
- Riviere-du-Loup (Gaspe, Quebec) – Joint Venture of Cacouna Energy, TransCanada and PetroCanada

Hurricanes Katrina and Rita are continuing to have a significant impact on the US Gulf Coast's energy infrastructure (most importantly for the short-term forecast natural gas deliverability) and equally important (and potentially longer term impact) on market psychology. The EIA reported that 47% of US Gulf Coast natural gas production capability remained out of service as of November 2, 2005. These supply and transportation outages have been reflected in spot prices for natural gas.

Figure 4 - Natural Gas Spot Prices (US$/mmBtu)



Natural Gas – PSM Input

The natural gas forecast used in the PSM is based on a Henry Hub forecast price. The Henry Hub is owned and operated by Sabine Pipe Line LLC, and is physically located at Sabine's Henry Gas Processing Plant in Louisiana where it interconnects nine interstate and four intrastate pipelines. Approximately 49 percent of U.S. wellhead production either occurs near the Henry Hub or passes close to the Henry Hub as it moves to downstream consumption markets. Since Henry Hub represents the largest centralized point for natural gas spot and futures trading in North America, it was selected for use in the model due to its liquidity and the availability of long term forecasts. The actual forecast used in the model was produced by Sproule and is outlined in the main OPA report.

The Henry Hub price is then adjusted to reflect the forecast basis differential between Henry Hub and Dawn, Ontario, which represents the key natural gas trading point in Ontario. The

basis differential represents the difference in value for a commodity between two separate locations. This difference can be influenced by commodity transportation costs as well as differences in supply and demand at the two separate locations. Finally, the burner tip price of natural gas is adjusted to reflect the cost of gas transport charges – one price for generation plants located near dawn and another higher price for those facilities located elsewhere in the province. The assumptions are identified below:

Table 3 - Forecast Basis Differential and Local Transport Costs

	US $ per mmBtu		
Year	Basis to Dawn	LDC Charge away from Dawn	LDC Charge at Dawn
2006	$0.30	$0.14	$0.06
2007	$0.40	$0.14	$0.06
2008	$0.32	$0.14	$0.06
2009	$0.60	$0.15	$0.06
2010	$0.47	$0.15	$0.07
2011	$0.43	$0.15	$0.07
2012	$0.74	$0.15	$0.07
2013	$0.72	$0.15	$0.07
2014	$0.76	$0.15	$0.07
2015	$0.73	$0.16	$0.07

Oil

At the end of August 2005, spot prices for WTI crude traded at Cushing, Oklahoma hit an all time high of $69.91 per barrel. Since then, prices have retreated somewhat and fallen below $60 per barrel but remain much higher than historical averages. Prices are being held up by:

- Tight margins in OPEC and non-OPEC nations mean that any supply disruption would be widely felt
- Political tensions in producer countries such as Saudi Arabia, Nigeria, Venezuela and Iraq which lead to a "security" premium under which short sellers risk having to cover contract commitments during periods of supply disruptions
- Global economic growth especially in developing countries such as India and China
- Consumption has caught up with installed crude and refining capacity and as such, capacity limitations are being tested

The challenge in developing any long term forecast under the current pricing climate is to estimate when or if these elevated crude prices will return to historical trading ranges. Navigant Consulting utilized a long term forecast that is a combination of short term NYMEX market futures and the "High B World Oil Price" and "Reference" cases described in the EIA

Annual Energy Outlook 2005, which are based on market fundamentals. The prices for #2 fuel oil and #6 residual oil are based on the historical relationship between these fuels and the spot price of crude oil.

Table 4 – Forecast Crude and Refined Oil Prices

	USD$/Barrel	USD$/mmBtu	
Year	Crude Oil	#2 Fuel Oil @ Southern Ontario	#6 Residual Oil @ Southern Ontario
2006	$59.87	$12.18	$6.83
2007	$56.42	$11.51	$6.49
2008	$53.17	$10.88	$6.18
2009	$50.11	$10.28	$5.88
2010	$47.22	$9.72	$5.60
2011	$48.79	$10.03	$5.75
2012	$50.42	$10.34	$5.91
2013	$52.09	$10.67	$6.07
2014	$53.83	$11.01	$6.24
2015	$55.62	$11.36	$6.41

The price forecast for #2 fuel oil and #6 residual oil include transport charges to plants located in Southern Ontario.

Lennox Specific Fuel Assumptions

Since the Lennox facility can burn either oil or natural gas and the model does not have the capability to dynamically switch fuels based on market prices, it was necessary to estimate a seasonal schedule for fuel burned at Lennox. Based on historical trends, forecast fuel prices, the expectation that natural gas prices will peak in the winter months and our understanding of the availability of natural gas for Lennox in the winter months, Navigant Consulting devised the following profile of fuel used at Lennox:

Table 5 - Lennox Fuel Profile

Month	% #6 Residual Oil	% Natural Gas
January	50%	50%
February	50%	50%
March	40%	60%
April	0%	100%
May	0%	100%
June	0%	100%
July	0%	100%
August	0%	100%
September	0%	100%
October	0%	100%
November	30%	70%
December	40%	60%

On a monthly basis, the PSM uses this profile to develop a blended fuel price comprised of a weighted value of prevailing natural gas and residual oil prices. This weighted price is then used in the dispatch logic for the Lennox variable cost estimate.

Coal

Increasing demand from existing electricity generating units and flat coal production levels have caused Central Appalachian coal price have doubled over the last 36 months. Supply increases have been constrained by a depletion of the most productive coal reserves, labour shortages, and the lead times required to bring on additional production. At current price considerable production can be brought on line and these high price levels have strengthened the contract market allowing this production to be brought on

The coal price forecast used in the PSM was developed from the fuel costs identified in the "Cost Benefit: Replacing Ontario's Coal Fired Electricity Generation" report provided to the Ministry of Energy.

Table 6 - Coal Price Forecast

Year	USD$/mmBtu				
	Lambton 3 & 4 (High Sulfur Bituminous)	Lambton 1 & 2 (Low Sulfur Bituminous)	Nanticoke (Blend of Low Sulfur Bituminous and PRB)	Atikokan (Low Sulfur Lignite)	Thunder Bay (Low Sulfur Lignite)
2006	1.80	2.36	2.04	1.24	1.27
2007	1.85	2.43	2.10	1.27	1.30
2008			2.16		
2009			2.22		

Longer term coal prices used for future technologies such as coal gasification are based on high sulphur bituminous coal which is escalated at an annual average rate of 1.5% on a nominal basis.

3.6 HYDROELECTRIC GENERATION

Based on historical operating characteristics provided by the OPA, hydroelectric generating units in the PSM are categorized as either run-of-river or dispatchable. Run-of-river units are assumed to dispatch evenly throughout the day while dispatchable resources generate most of their energy during peak periods when power prices are at their highest.

Run-of-River Assumptions

Since the energy output from hydroelectric resources varies by season due to the variability in water flows, the PSM applies a seasonal profile to the energy production for these units. The following seasonal profile, as provided by the OPA, adjusts the total energy produced by run-of-river hydroelectric resources.

Table 7- Monthly Hydro Availability

Month	Monthly Avg. Availability
Jan	60.4%
Feb	61.3%
Mar	58.8%
Apr	64.1%
May	68.9%
Jun	62.4%
Jul	53.4%
Aug	50.0%
Sep	50.8%
Oct	55.1%
Nov	59.7%
Dec	59.7%

Dispatchable Assumptions

In addition to the above seasonal profile, dispatchable hydroelectric resources are adjusted by the following weekly profile:

Table 8 - Hourly Hydroelectric Availability

Hour	% of Annual Daily Average Energy						
	Mon	Tues	Wed	Thurs	Fri	Sat	Sun
1	60%	60%	60%	60%	60%	60%	60%
2	54%	54%	54%	54%	54%	54%	54%
3	50%	50%	50%	50%	50%	50%	50%
4	49%	49%	49%	49%	49%	49%	49%
5	52%	52%	52%	52%	52%	52%	52%
6	60%	60%	60%	60%	60%	60%	60%
7	75%	75%	75%	75%	75%	75%	75%
8	99%	99%	99%	99%	99%	99%	99%
9	110%	110%	110%	110%	110%	110%	110%
10	119%	119%	119%	119%	119%	119%	119%
11	127%	127%	127%	127%	127%	127%	127%
12	128%	128%	128%	128%	128%	128%	128%
13	126%	126%	126%	126%	126%	126%	126%
14	122%	122%	122%	122%	122%	122%	122%
15	121%	121%	121%	121%	121%	121%	121%
16	126%	126%	126%	126%	126%	126%	126%
17	134%	134%	134%	134%	134%	134%	134%
18	134%	134%	134%	134%	134%	134%	134%
19	130%	130%	130%	130%	130%	130%	130%
20	131%	131%	131%	131%	131%	131%	131%
21	124%	124%	124%	124%	124%	124%	124%
22	106%	106%	106%	106%	106%	106%	106%
23	92%	92%	92%	92%	92%	92%	92%
24	72%	72%	72%	72%	72%	72%	72%

3.7 FORCED OUTAGE AND PLANNED MAINTENANCE RATES

As outlined earlier in the report, the PSM calculated monthly available capacity net of assumed forced outage and planned maintenance rates. The rates assumed in the model, which are based on historical and forecast performance of certain technologies as well as input from the IESO forecast, are as follows:

Table 9 - Forecast Outage Rates

	Existing Nuclear	New Nuclear	Coal	Existing Gas	Generic Gas	IGCC
Forced Outage	4% - 7%	5%	5%	5%	5%	5%
Planned Maintenance	4% - 10%	5%	5% - 8%	8%	5%	5%

These rates exclude the impact from major maintenance when one or more units are out for refurbishment.

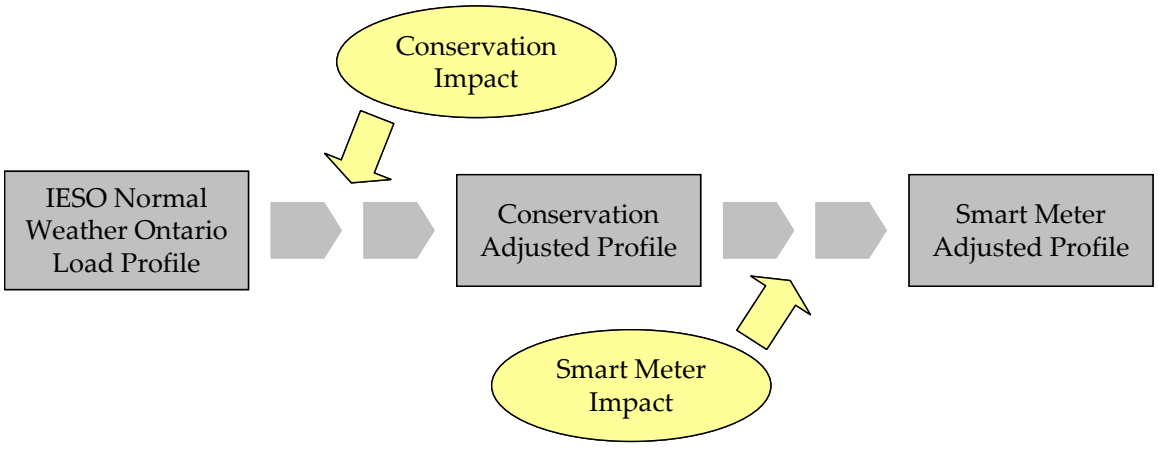
4 LOAD PROFILE DEVELOPMENT

4.1 INTRODUCTION

Collectively, electricity consumers in Ontario use electricity in a distinct and regular pattern throughout the year. This pattern is called a "load profile". Load profiles differ between the various sectors, for example the residential load profile is different from either the industrial or commercial load profile profiles and the industrial profile is different from the commercial load profile. Unless the proportion of consumption by each sector relative to the total changes significantly within the province, Ontario's overall load profile is expected to remain relatively stable over time. Conservation and other load shifting mechanisms can also affect the load profile.

As part of the portfolio screening analysis, Navigant Consulting developed: 1) a base load profile consistent with the IESO's normal weather forecast; 2) "decrement" profiles for four different conservation scenarios; and 3) a load profile reflecting the impact of smart-meters and time-of-use rates in all Ontario homes and businesses. As shown in Figure 5, the decrement profiles for each of the four conservation scenarios were subtracted from the base load profile to obtain a conservation adjusted profile. The load shifting impact of smart meters were then applied to the conservation adjusted profile. The final result is a load profile which has been adjusted for both conservation and smart meter impacts, and best reflects the pattern of electricity consumption in Ontario going forward under the various conservation scenarios.

Figure 5: Methodology for Applying Conservation and Smart Meter Impacts

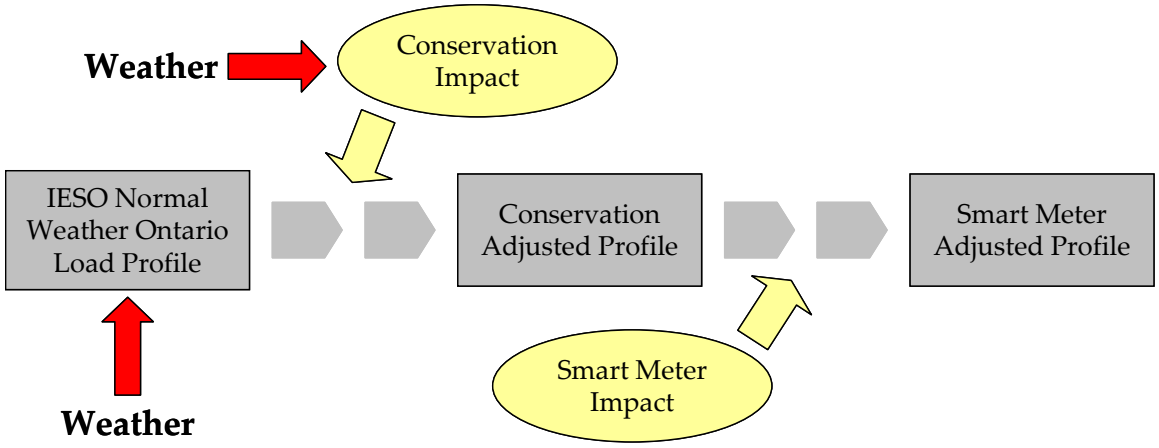


Many factors contribute to the pattern of electricity consumption, not the least of which is weather. Variations in weather provide the most significant short-term variations in a load profile. For example, on summer days when the temperature is very high, increases in air-conditioning load create a profile which is much more pronounced (higher consumption during peak periods) than other times when the weather is milder. Electric heating load has a similar

impact on winter days. In contrast to air conditioning load however, heating load tends to be spread over the entire day, which generally maintains the shape of the original load profile but at a higher level.

As discussed, the base load profile developed by Navigant Consulting reflects normal weather conditions. To better reflect actual weather conditions that Ontario will experience, Navigant Consulting also developed a method for modeling weather impacts on demand. As indicated in Figure 6, weather impacts are applied to 1) the base profile and 2) the heating and cooling component of the conservation impact. For this analysis, we have assumed that the smart meter impact remains constant regardless of the weather impact on base demand and conservation. This approach results in a conservative estimate of the impact of smart meters on a very hot summer day when the annual peak is likely to be achieved.

Figure 6: Methodology for Applying Weather Impacts to Demand Profiles



In this section of the report, we present the assumptions, analytic approach and results of Navigant Consulting's development of these various load profiles and weather impacts.

4.2 ONTARIO LOAD PROFILE

The portfolio screening model (PSM) dispatches generation within each hour of the forecast period to meet hourly demand levels. The hours in which generators are deemed to operate within the model, and as a result the market revenues they earn, is therefore primarily a function of the demand in each hour.[4] As such demand forecasts play a crucial role in the portfolio screening analysis.

To reduce the run time of the model and allow for greater operating flexibility, the PSM was developed based on a typical week per month approach. Instead of dispatching load for 8760 hours per year (or 8784 in a leap year), the model only simulates 2,016 hours per year. That is,

[4] Characteristics such as operating costs, forced and unforced outages are also contributing factors.

seven days (one week) per month. The load profiles developed by Navigant Consulting for this analysis were thus required to also be typical week profiles. The results of the typical week analysis are extrapolated to annual results based on the number of days within each month.

4.2.1 Annual Energy and Peak Demand Forecasts

The primary source for the annual demand forecast used by Navigant Consulting is the "IESO 10 Year Outlook: Demand Forecast" released in July of 2005.[5] The report represents the most recent publicly available Provincial demand forecast available at the time this analysis was conducted.

The IESO outlook contains several scenarios for both energy consumption and peak demand. For the purposes of defining a base case for the portfolio screening model, we have used the "Median Growth" scenario for energy consumption and the "Normal Weather" scenario for peak demand.

The IESO outlook forecasts peak demand and annual energy consumption for 2006 through 2015. To extend the forecast through 2025 we have extrapolated the 2015 values based on the cumulative annual growth rate (CAGR) forecast by the IESO. Energy consumption is expected to grow by approximately 0.9% and peak demand is expected to grow by approximately 1.3%. Table 10 presents annual peak demand and consumption based on these assumptions from 2006 through 2025.

Table 10: Ontario Peak Demand and Energy Consumption Forecast (2006 – 2025)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Annual Energy (TWh)	156.8	158.3	160.3	161.2	162.6	164.2	166.0	167.0	168.4	169.7
Peak Demand (MW)	24,205	24,374	24,627	25,045	25,228	25,534	25,840	26,158	26,461	26,874

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy (TWh)	171.2	172.7	174.3	175.8	177.4	178.9	180.5	182.1	183.7	185.3
Peak Demand (MW)	27,211	27,552	27,898	28,248	28,602	28,961	29,324	29,692	30,064	30,441

The values provided in the tables above represent the amount of energy necessary to meet provincial demand at the generator level. In other words, "the Ontario demand is the sum of

[5] The report is available on the IESO website at: http://www.ieso.ca/imoweb/pubs/marketReports/10Year_ODF_2005jul.pdf

coincident loads plus losses on the IESO controlled grid".[6] Excluded from this forecast is the additional electricity generated for export purposes.

4.2.2 IESO Load Profile

As stated, the starting point for the development of the typical week profile was the IESO's normal weather hourly annual profile which was used in the 10 Year Outlook. The annual energy forecast presented in Table 10 matches the sum of the demand in each hour of the profile, and the peak demand forecast presented in Table 10 corresponds to the largest demand value in the hourly profile for each year.

The detailed assumptions regarding the IESO's development of the demand forecast and the hourly profile are available on their website in a document entitled "Methodology to Perform Long Term Assessments".[7]

4.2.3 Typical Week Profile

The typical week profile was developed in two stages. The first stage corresponds to the period covered by the IESO 10 Year Outlook covers (2006 – 2015), for which the IESO provided its annual hourly profile. The second stage corresponds to the period over which the annual values were extrapolated (2016 – 2025)

For the period 2006 through 2015, the typical week profile was extracted from the annual hourly profile provided by the IESO. Hourly data for one week in each month for every year was selected with care taken to ensure that a) the week containing the annual peak demand value was one of the twelve weeks selected, and b) the annual energy closely approximated the IESO forecast value when the weekly data was summed and extrapolated to an entire year,. As Table 11 indicates the annual energy is within half a percent of the IESO forecast value on average over the ten year period. Since the week containing the annual peak demand was a mandatory selection the annual peak achieved in the typical week profile is always a perfect match with the annual peak in the IESO profile.

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6 IESO 10 Year Outlook: Demand Forecast , July 2005

7 Available on IESO website at: *http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2005jun.pdf*

Table 11: Comparison of Total Energy in IESO Annual Hourly Profile and the Typical Week Profile (Normal Weather)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Avg
IESO Annual Hourly Profile											
Annual Energy (TWh)	156.8	158.3	160.3	161.2	162.6	164.2	166.0	167.0	168.4	169.7	
Normal Weather Peak Demand (MW)	24,205	24,374	24,627	25,045	25,228	25,534	25,840	26,158	26,461	26,874	
Typical Week Profile Extrapolated											
Annual Energy (TWh)	158.4	159.6	159.5	161.2	163.6	165.6	166.9	166.8	168.4	169.8	
Normal Weather Peak Demand (MW)	24,205	24,374	24,627	25,045	25,228	25,534	25,840	26,158	26,461	26,874	
Difference											
Annual Energy (TWh)	0.99%	0.78%	-0.52%	0.00%	0.61%	0.85%	0.58%	-0.12%	-0.02%	0.05%	0.32%
Peak Demand (MW)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

An alternate approach to would have been to take an average of the corresponding hourly demands for each day of the week within a month and develop the typical week profile based on the result. The decision was made to not use this approach because of the detrimental smoothing effect averaging would have had on the profile (for example, the annual peak demand would not match the IESO forecast given the smoothing effect of averaging).

For the remaining ten years of the analysis period (2016 – 2025), the 2015 typical week profile was extrapolated and fit to the annual energy and peak demand forecast assumptions in a three-step process. In the first step, demand in each hour was scaled up by the year-over-year growth in the forecast annual energy. In most instances because the energy growth differs from the peak demand growth this results in a difference between the peak demand forecast and the peak demand determined as the maximum value in the profile. In the second step, this difference in peak demand (2% on average over the ten year period) was corrected by adding energy to every hour on the single day containing the peak demand. This then results in a very small discrepancy between the forecast annual energy and the annual energy determined as the extrapolated sum of the hourly typical week profile. This small discrepancy was corrected in the third step by reducing the energy throughout the remainder of the year (excluding the day containing the peak demand) slightly. The relatively small amount of energy required to be redistributed results in a negligible effect.

The following figures provide load profiles for a typical week and a typical working weekday for Ontario in 2015, under normal weather conditions.

Figure 7: Ontario Typical Normal Weather Weekly Demand Profile (2015), January and July

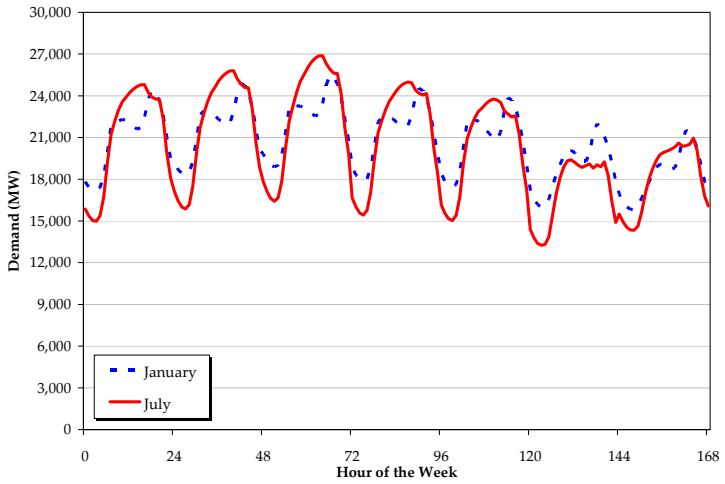
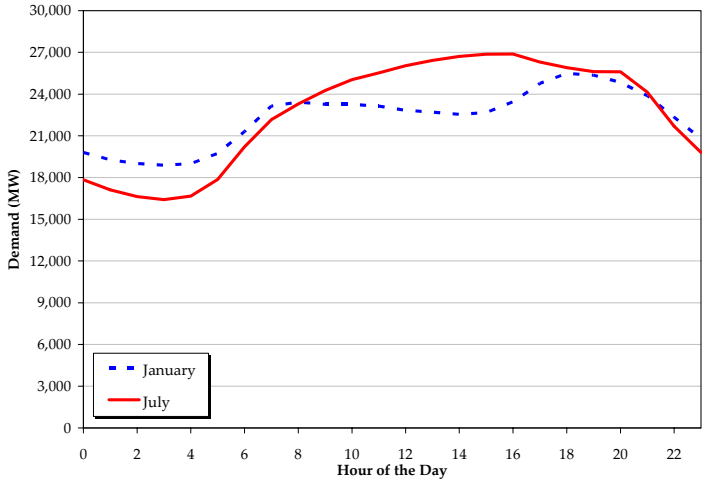


Figure 8: Ontario Typical Normal Weather Daily Demand Profile (2015), January and July



4.3 CONSERVATION AND DEMAND MANAGEMENT DECREMENT PROFILES

The IESO 10 Year Outlook is quite clear as to the level of conservation and demand response embedded within its forecast. Instances of conservation, such as the gradual replacement of old worn-out appliances with new efficient ones, the construction of buildings and homes with better insulation to replace old existing structures are all "occurring naturally", and as such are embedded within the forecast.[8] "Higher levels of conservation and demand management are possible but require more direct intervention in the market through incentives, standards or

[8] "Occurring naturally" is the term used in the IESO 10 Year Outlook: Demand Forecast, July 2005

other mechanisms"[9], and are not accounted for in the IESO forecast because of the difficulty associated with assessing their potential.

The potential conservation impacts resulting from direct intervention were developed by ICF Consulting (ICF). Using these conservation impacts from ICF, Navigant Consulting then developed decrement profiles which could be used to reflect the impact of conservation on the Ontario load profile.

Navigant Consulting developed decrement profiles for four conservation scenarios provided by ICF. The scenarios represent varying standard levels as well as the aggressiveness of conservation programs. The scenarios analyzed were:

1) Very aggressive conservation program plus very aggressive standards (dated Aug 25th, 2005),

2) Very aggressive conservation program (dated Oct 7th, 2005),

3) Moderately aggressive conservation program (dated Aug 25th, 2005), a

4) Moderately aggressive conservation program scenario (dated Oct 7th, 2005)

The conservation estimates provided by ICF are presented in aggregate as well as broken down by end-use or segment-specific savings for each of the three consumer sectors, residential, industrial and commercial.

The methodology used to develop the conservation decrement profiles from the ICF annual savings estimates was relatively straightforward. The methodology was applied in the same manner to all four of the conservation scenarios. For simplicity, the following discussion, tables and figures summarize the approach used to develop the decrement profile for the moderately aggressive conservation program (Aug 25).

4.3.1 Segment-specific and End-use Load Profiles

Available on the IESO website[10] are normal weather residential load profiles by end-use as well as normal weather segment-specific profiles for the commercial and industrial sectors. The profiles contain a typical weekday and weekend day for each month of the year. Navigant Consulting used these profiles as the basis for the typical week conservation decrement profiles.

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9 IESO 10 Year Outlook: Demand Forecast, July 2005

10 http://www.ieso.ca/imoweb/transInfo/demand.asp

The end-use and segment-specific conservation estimates provided by ICF were aggregated based on their fit within the available end-use and segment-specific profiles on the IESO website. The profiles available on the IESO website that correspond to the ICF identified end-uses and segments are listed below. All of the profiles identified are representative of normal weather conditions.

1) Residential end-use profiles available include: Baseload, Space Heating, Base Board, Central Air, and Water Heating.

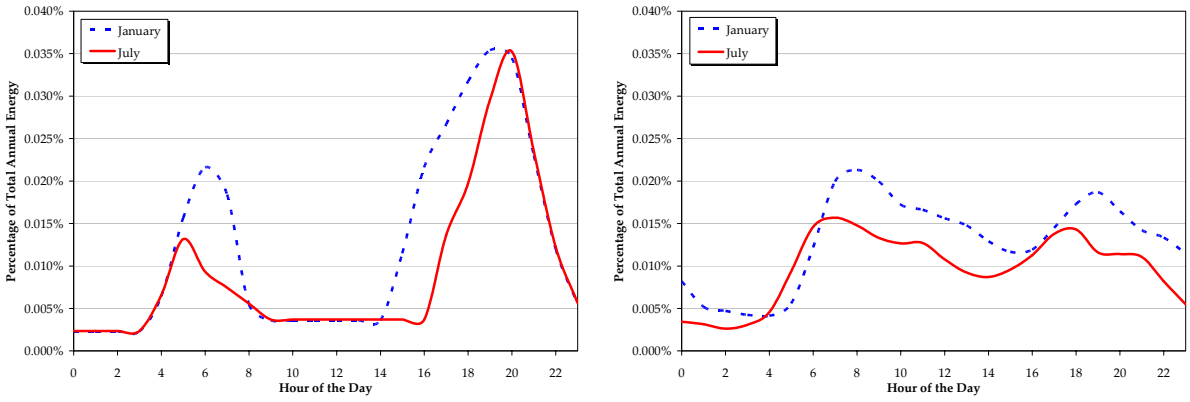
2) Commercial segment-specific profiles available include: Educational, Recreational, Accommodation, Food, Healthcare, Offices, Other Retail, Warehouses, Multi-Residential, and Services.

3) Industrial segment-specific profiles available include: Petroleum, Chemicals, Construction, Fabricated Metals, Mining, Non-metallic Minerals, Other Manufacturing, Primary Metals, Wood Products Manufacturing, and Farm/Forestry/Fishing.

In addition to the profiles mentioned above, Navigant Consulting developed a residential lighting profile based on data available through the Building America Program at the US Department of Energy.[11]

Examples of the residential end-use, commercial and industrial segment specific profiles for a working weekday are provided in Figure 9, Figure 10, and Figure 11. The end-use and segment-specific profiles are normalized such that the value in each hour represents the percentage of annual energy consumed in that hour.

Figure 9: Residential Lighting (Left) and Water Heat (Right) End-use Profiles



11 http://www.eere.energy.gov/buildings/building_america/

Figure 10: Commercial Educational (Left) and Office Use (Right) Segment-specific Profiles

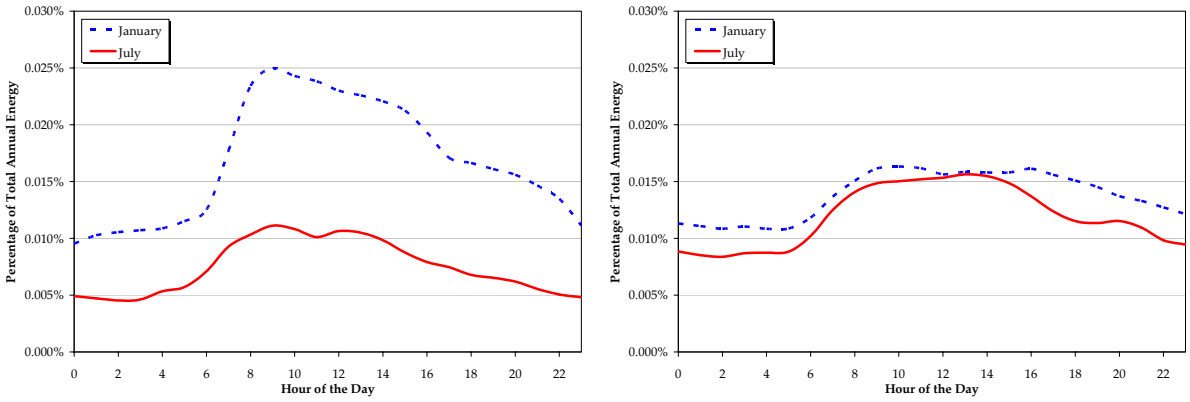
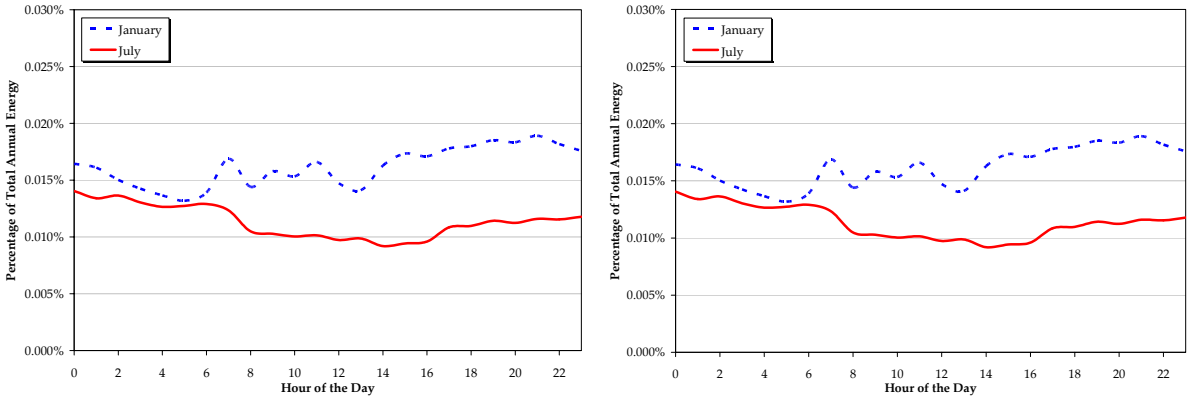


Figure 11: Industrial Chemical (Left) and Petroleum Refining (Right) Segment-specific Profiles



4.3.2 Application of ICF Estimates to End-use and Segment-specific Profiles

The conservation estimates provided by ICF are presented in two forms, as annual energy savings, and as an impact on annual peak demand. The annual energy saving estimates provided by ICF were scaled up by 9.2% before being applied to the end-use and segment specific profiles to account for losses.[12]

Each of the end-uses and segments identified by ICF was assigned to a specific profile (available profiles were identified in the previous section). In some instances because of the unavailability of profiles multiple end-uses or segments were applied to the same profile. Figure 12 depicts this assignment for residential sector end-uses. Commercial and industrial segments were assigned in a similar manner.

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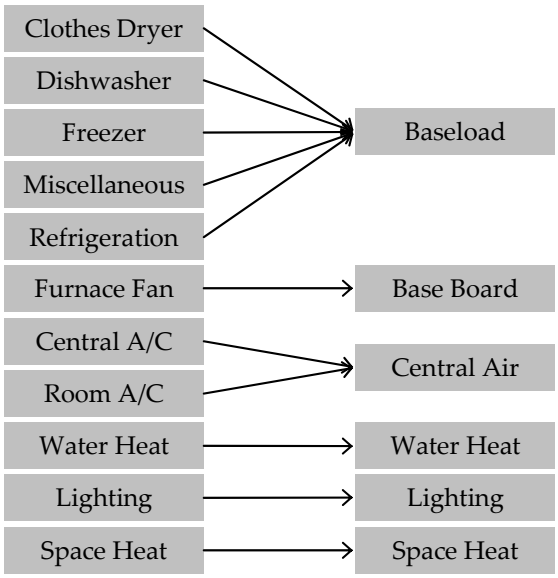
12 The annual energy conservation estimates provided by ICF are representative of the savings at the load level. The Ontario energy and peak forecasts and the load profile developed by Navigant Consulting are all representative of demand at the generator level. The OPA advised Navigant Consulting that the ICF estimates of annual energy conservation estimates should be scaled up by a factor of 9.2%.

Figure 12: Assignment of Residential End-use Conservation Estimates to Available Profiles



The annual ICF energy conservation estimates for each end-use or segment was then multiplied by each hour of its respective profile. The individual profiles were aggregated in each year to form a sector decrement profile for each of the three sectors, residential, commercial and industrial.

4.3.3 Total System Conservation Decrement Profiles

The three sector conservation decrement profiles were then aggregated again to form the total system conservation decrement profile. For each year of the analysis period there is a different conservation decrement profile because a) the total amount of conservation in the ICF estimates changes over time, and b) the relative contribution of each end-use or segment to the total also changes over time.

The normal weather conservation decrement profiles for a working weekday in January and July in 2015 are shown in Figure 13.

Figure 13: Conservation Decrement Profiles for a Typical Weekday in January (Left) and July (Right)

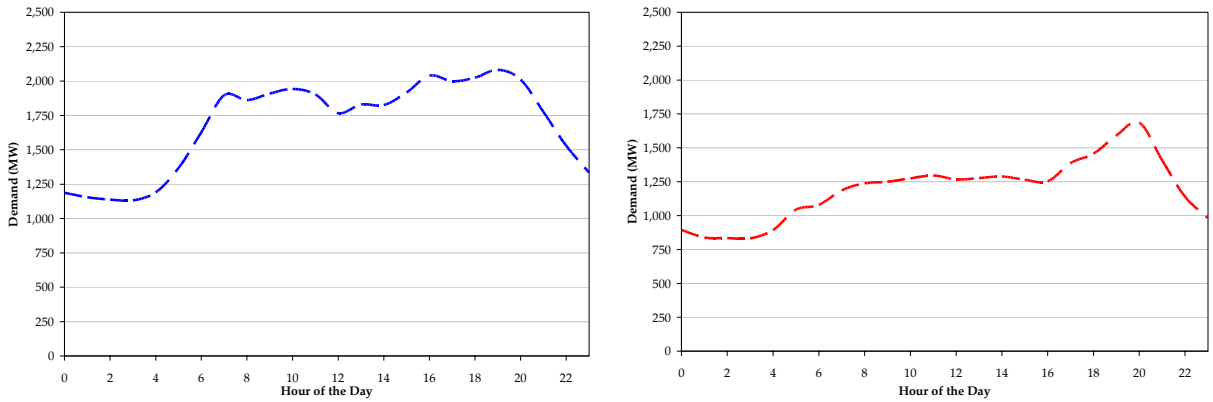


Figure 14 and Figure 15 show the impact those decrements have on the total system load for the respective days.

Figure 14: Impact of Conservation on Ontario Load Profile, Typical Weekday January 2015

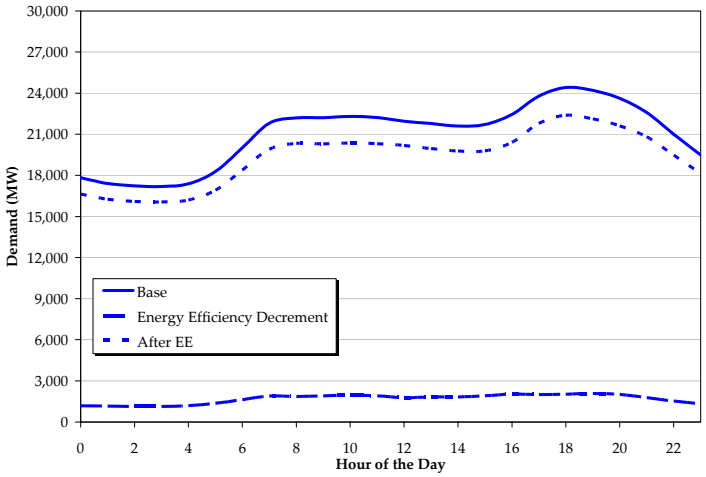


Figure 15: Impact of Conservation on Ontario Load Profile, Typical Weekday July 2015

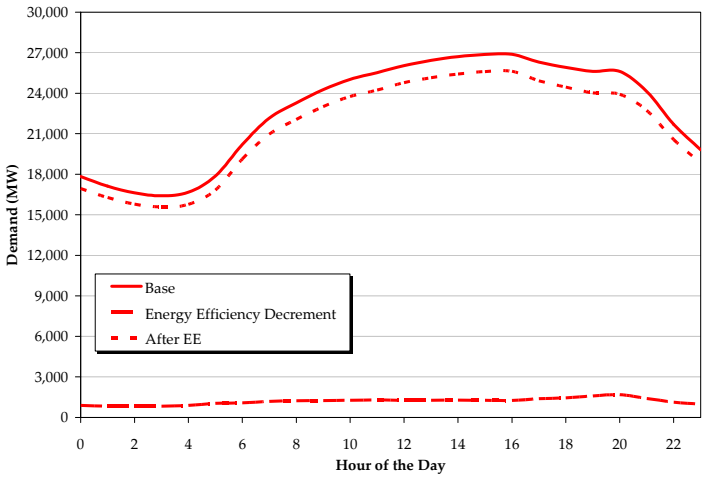


Table 12 presents the impact of conservation decrement (for the moderately aggressive program – Aug 25) on the forecast annual peak demand and energy consumption.

Table 12: Normal Weather Conservation Impacts (2006 – 2025)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Peak Demand (MW)										
Before Conservation	158.4	159.6	159.5	161.2	163.6	165.6	166.9	166.8	168.4	169.8
After Conservation	24,205	24,374	24,627	25,045	25,228	25,534	25,840	26,158	26,461	26,874
After Conservation										
Annual Energy (TWh)	157.1	156.1	153.8	153.7	154.7	155.8	156.1	155.9	157.4	158.9
Peak Demand (MW)	23,989	23,931	24,004	24,160	24,311	24,539	24,750	25,040	25,360	25,675
Difference										
Annual Energy (TWh)	1.3	3.5	5.7	7.5	9.0	9.8	10.8	10.9	11.0	10.9
Peak Demand (MW)	216	443	622	884	917	995	1,090	1,118	1,100	1,199

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Before Conservation										
Annual Energy (TWh)	171.3	172.8	174.4	175.9	177.4	179.0	180.6	182.2	183.8	185.4
Peak Demand (MW)	27,211	27,552	27,898	28,248	28,602	28,961	29,324	29,692	30,064	30,441
After Conservation										
Annual Energy (TWh)	160.6	162.3	164.0	165.7	167.7	169.8	171.7	173.8	175.8	177.9
Peak Demand (MW)	25,959	26,292	26,634	26,992	27,375	27,767	28,162	28,568	28,978	29,400
Difference										
Annual Energy (TWh)	10.7	10.6	10.4	10.1	9.7	9.2	8.8	8.4	8.0	7.5
Peak Demand (MW)	1,252	1,260	1,264	1,256	1,227	1,194	1,162	1,124	1,086	1,041

The peak demand decrements provided in Table 12 are representative of the impact of conservation under normal weather conditions. This is the due to fact that the end-use, and segment-specific load profiles are based on normal weather conditions. In discussion with ICF

it was identified that the peak impact values provided in their report are for a hot summer day – that is, above normal temperatures.[13] As such, there is a discrepancy between the peak demand decrement identified by ICF and the peak demand decrement based on the load profiling analysis. The discrepancy is to be expected, since the two decrements reflect different underlying weather conditions. This discrepancy is accounted for and corrected through the stochastic weather modeling which is discussed in more detail in the last sections of this chapter. In simple terms, during summer months when the Ontario profile is adjusted for weather in the stochastic weather modeling, the conservation decrement is also adjusted. The end result of this adjustment is a decrement on a hot summer day which is in-line with the ICF estimate.

The result of the above analysis is a conservation adjusted load profile which reflects the conservation impacts provided by ICF. However, this profile does not reflect the load shifting impact that smart meters and dynamic pricing are expected to have on consumption patterns. The following section describes the approach used to reflect this load shifting impact.

4.4 SMART METER IMPACT

The government of Ontario has established a target for the installation of smart meters for all Ontario customers by December 31, 2010, with an interim target of 800,000 smart meters installed by 2007.

In contrast to the conventional metering currently used for most residential and small commercial customers in Ontario, smart meters are able to track consumption in hourly (or finer) intervals and report this information to a central data warehouse, allowing the use of Time-Of-Use (TOU) pricing and Critical Peak Pricing (CPP) and enabling load shifting, demand response and conservation, as well as eliminating the need for manual meter reads and providing other benefits to local distribution companies (LDCs).

Navigant Consulting was asked to estimate the impact that the installation of smart meters and introduction of dynamic pricing would have on Ontario's electricity demand patterns (or load profile).

Broadly speaking, Navigant Consulting's analysis comprised the following three tasks:

1) Develop the aggregate "before-smart meter" load shape of residential and small commercial customers that will be receiving smart meters

2) Estimate the appropriate elasticity that would apply to each customer sector, and

[13] In an email received from the OPA, ICF Consulting identified that "The peak savings projections are consistent with a peak summer day (not weather normalized)"

3) Develop the aggregate "after-smart meter" load shape based on the estimated elasticity and the expected TOU prices that would apply to the customers.

In simple terms, the difference between the "before" and "after" load shapes represents the amount of load that is transferred from on-peak to off-peak periods.

The potential impact of Critical Peak Pricing (CPP) was not addressed in Navigant Consulting's analysis. Hence, the results provided herein may understate the actual degree to which smart meters help reduce peak demand in Ontario. Note however, that the resultant load profile, after accounting for the impact of conservation and load shifting due to TOU pricing is much flatter than it is at present, which could limit the potential for incremental peak demand reduction from CPP. Further analysis would be required to accurately estimate this incremental peak demand reduction impact beyond conservation and TOU-induced load shifting.

The following sections present the results of Navigant Consulting's analysis.

4.4.1 Sector Load Shapes

The starting point for Navigant Consulting's estimation of the "before smart meter" load shape was an estimate of the Net System Load Shape (NSLS), which essentially represents the total load of all local distribution companies (LDCs) in Ontario, less the load of all LDC customers with interval meters.

No NSLS for the entire province is readily available. Some LDCs do however make available the NSLS for their service area. To obtain a province wide NSLS, Navigant Consulting used a weighted aggregate of a representative sample of LDC specific load shapes from across Ontario.

Overall Regulated Price Plan (RPP) consumption is approximately 74 TWh annually, but this includes some prescribed customers (e.g., hospitals, schools and municipal facilities, such as water treatment plants) with interval meters. To account for this, Navigant Consulting reduced the overall NSLS load to 67 TWh (2006). Although the prescribed customers have interval meters, they are currently not exposed to time-varying prices. However, over time they will be exposed to time-varying prices and would be expected to change their consumption patterns in response to the time-varying prices. Hence, excluding this group will understate the magnitude of load shifting, but strictly speaking, their response cannot be attributed to the installation of smart meters since these customers already have interval meters.

Because elasticities vary between residential and small commercial customers (as discussed in the following section), Navigant Consulting developed unique load profiles for each of these two customer sectors. The load profile for commercial customers without interval meters was derived first, and then this profile was subtracted from the NSLS to derive the residential load profile.

Conventionally-Metered Commercial Customer Load Shape

The commercial load shape for conventionally-metered commercial customers (i.e., commercial customers without interval meters) was largely based on the segment-specific load shapes available from the Independent Electricity System Operator's (IESO) website, weighted based on Navigant Consulting's estimate of their percentage of the total conventionally-metered commercial customer load.

Navigant Consulting's estimated breakdown of the conventionally-metered commercial customer load by segment is shown in Table 13. The breakdown by segment within the entire commercial sector is based on 2001 data from NRCan Office of Energy Efficiency.[14] Note that most segments are estimated to represent roughly the same percentage of the conventionally-metered commercial customer as the total commercial load with the exception of:

1) offices, for which the bulk of the segment load is estimated to be in interval-metered facilities (hence offices represents a greater percentage of the total commercial load than of the conventionally-metered commercial customer load),

2) hotels and other accommodation, for which more of the segment consumption is estimated to be within the conventionally-metered commercial customer load and

3) bulk-metered multi-residential, for which the entire segment consumption is estimated to be within the conventionally-metered commercial customer load.

Note that the conventionally-metered commercial customer load includes bulk-metered multi-residential customer load. If the government introduces a policy to install sub-metering for multi-residential customers, then it would be appropriate to include the load in the residential sector load shape (and apply the higher residential elasticity). However, no policy decisions regarding sub-metering have been announced and, for this reason, it is appropriate to include the bulk-metered multi-residential load in the commercial load shape and to apply the lower commercial elasticity to this load.

[14] Ontario Commercial Energy Use Time Series, Source: Office of Energy Efficiency, Natural Resources Canada and Statistics Canada.

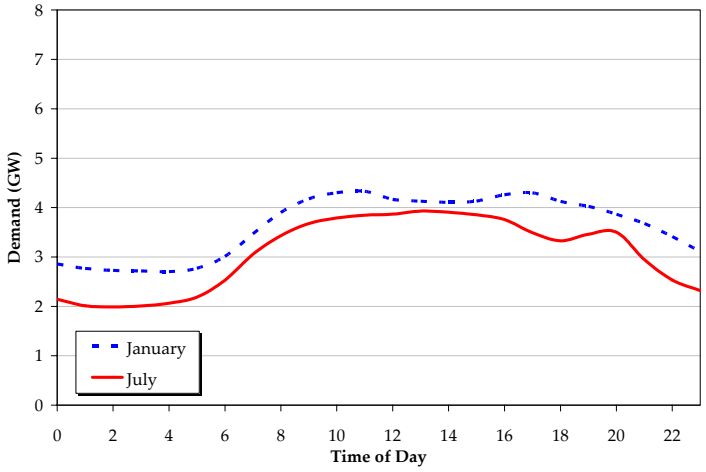
Table 13: Breakdown by Segment within Conventionally-Metered Commercial Customer Load and within Entire Commercial Sector

	Estimated Percentage of Conventionally-Metered Commercial Load	*Percentage of Total Commercial Load*
Education	4%	4%
Health Facilities	2%	3%
Religious Institutions	1%	1%
Services/Other	3%	3%
Offices	23%	40%
Retail (Composite)	17%	17%
Hotels and Other Accommodation	15%	11%
Recreational Facilities	5%	4%
Wholesale Warehouses	6%	5%
Bulk-Metered Multi-Residential	24%	13%
Total	***100%***	***100%***

The total conventionally-metered commercial customer consumption for 2006 is estimated to be roughly 27 TWh. The remaining commercial load is assumed to be already interval-metered.

Based on the load weighting given in Table 13, the resultant typical January and July weekday load shapes for conventionally-metered commercial customers in 2006 are presented in Figure 16. The maximum demand for this group of customers is estimated to be approximately 4.5 GW (4,500 MW). Although not shown, Navigant Consulting developed similar conventionally-metered commercial customer load shapes for weekdays in the remaining ten months of the year and weekend load shapes for twelve months of the year.

Figure 16: Typical January and July Weekday Conventionally-Metered Commercial Customer Profile



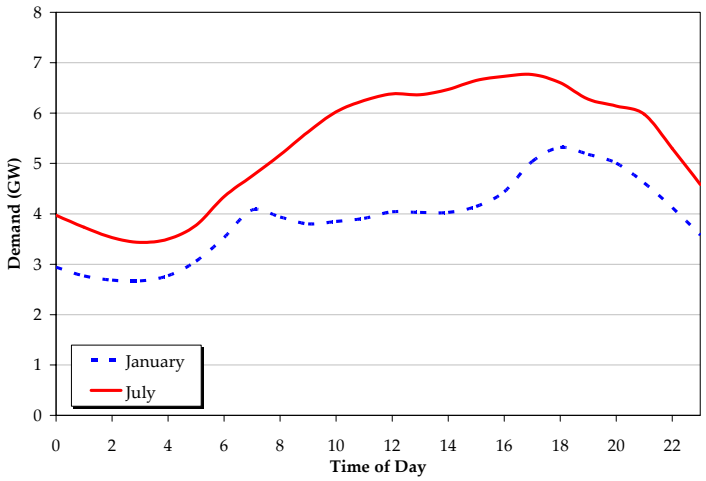
Note that the load of conventionally-metered industrial customers is not reflected in the above load shapes. Although the consumption of this group of customers is expected to be relatively

low, excluding this customer group from the analysis of what is more realistically the "business" customer group will produce results that are somewhat conservative, since industrial customers generally demonstrate higher elasticity of substitution than commercial customers.

Residential Load Shape

As discussed, the residential load shape was developed by subtracting the load shape for conventionally-metered commercial customers from the NSLS. The resultant residential load shape for January and July 2006 is shown in Figure 17.

Figure 17: Typical January and July Weekday Residential Customer Profile



Aggregate Load Shape

In summary, Navigant Consulting's estimate of the January load profiles for conventionally-metered commercial customers, residential customers and the overall NSLS are shown in Figure 18 and the July profiles for these customer groups are shown in Figure 19.

Figure 18: Typical January Weekday Profiles

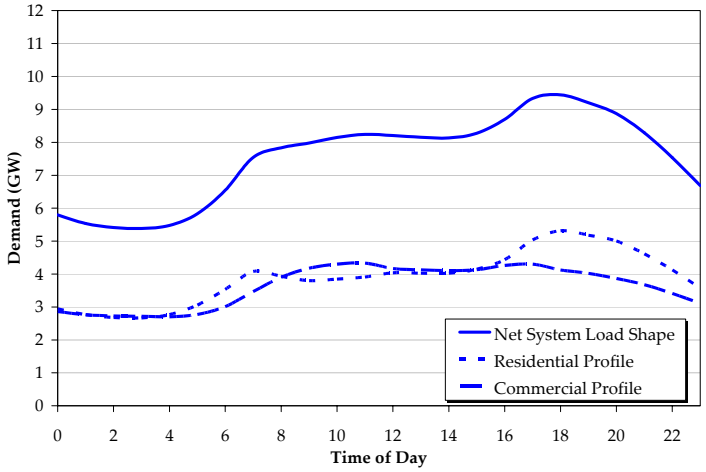
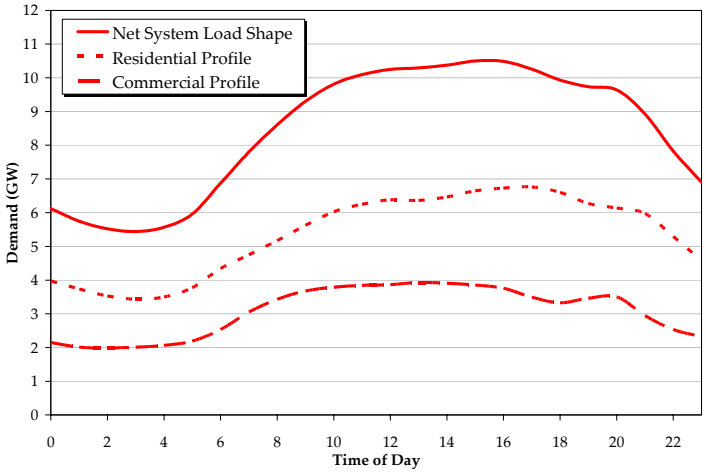


Figure 19: Typical July Weekday Profiles



Note that the illustrative profiles given above do not reflect the impact of conservation. As mentioned in the previous section, Navigant Consulting developed load profiles for each of four conservation scenarios. To more accurately estimate the impact of smart meters, Navigant Consulting also developed four smart meter impacts corresponding to the four conservation scenarios. The following analysis only presents the results for one of the four scenarios, the "moderately aggressive program (Aug 25)", however the same procedure was used to develop the smart meter impact for the remaining three. The resultant load shapes for January and July, after the effect of conservation, are given in Figure 20 and Figure 21. The conservation impact for conventionally-metered commercial customers was assumed to be the same percentage of the overall commercial conservation impact as the conventionally-metered commercial customers represent of the overall commercial load. The load shapes below represent 2006 levels of demand and conservation; hence the impact of conservation is relatively small. Overtime however, the impact is forecast to increase.

Figure 20: Typical January Weekday Profiles after Conservation Impact

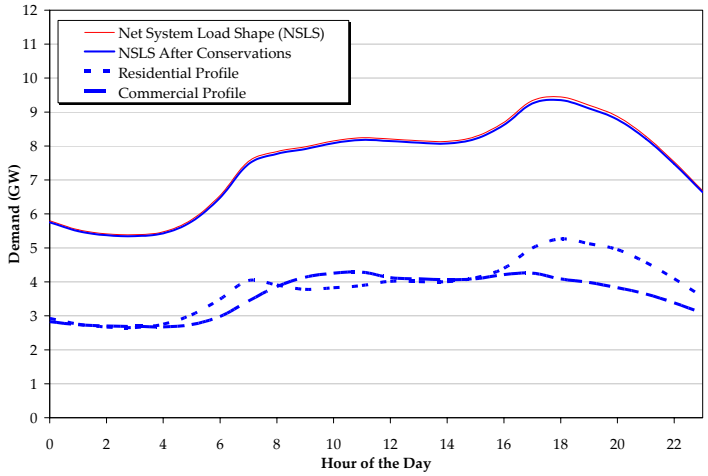
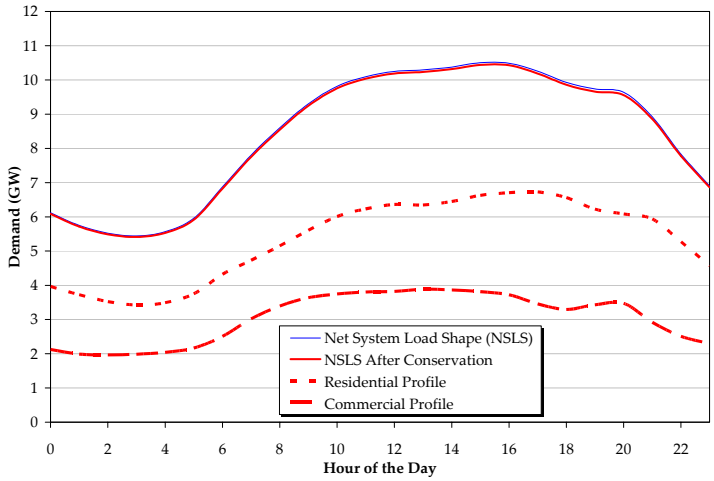


Figure 21: Typical July Weekday Profiles after Conservation Impact



4.4.2 Elasticity Estimates

Estimating the response of customers to the introduction of smart meters and dynamic pricing must start with an understanding of how customers will react to the new electricity price signals that they will be receiving. Economic theory holds that offering customers an opportunity to respond to electricity price signals promotes demand response in the form of load reduction or load shifting. As prices rise, customer demand is reduced. As prices drop, customer demand increases.

To investigate these effects, referred to as the price elasticity of demand, Navigant Consulting conducted a literature review of relevant studies covering residential, commercial and industrial demand response. The research focused on own price elasticity, a measurement of changes in consumption in the same time period in which the price change occurs, and elasticity of substitution, a shift in consumption across time periods.

Research Findings

Applications of time sensitive pricing in electricity markets for small business and residential customers are an emerging phenomenon and as a result, there is limited research available concerning demand response and elasticity in these markets. The available literature indicates that residential and commercial customers respond differently to time sensitive pricing and that even within those two broad categories, a wide range of customer responses to time sensitive pricing are possible.

The table below summarizes the range of responses from various studies and includes Navigant Consulting's estimates of elasticity for Ontario customers. The residential and commercial elasticities given are medium-term estimates that are expected to be realized five years after the installation of smart metering. The technology-enabled elasticities represent the elasticity that could be realized in the long term. Although we provide technology enabled elasticity estimates, in the interest of remaining conservative, we have not included them in our base analysis.

Table 14: Ontario Elasticity of Substitution Estimates

	Elasticity Range from other Jurisdictions	Estimated Elasticity for Ontario
Residential Customers	**0.04 to 0.14**	**0.11**
Commercial Customers	**0.03 to 0.14**	**0.06**
Residential – Technology-Enabled	0.13 to 0.39	0.22
Commercial – Technology-Enabled	0.04 to 0.12	0.12

Note that our estimates fall in the middle of the range of possible values for both customer segments from other studies. While this may not initially appear to be the case for residential customers, we have made an adjustment to reflect climates with characteristics that are more similar to Ontario's and our estimate is near the mid-point of this adjusted range. Additional information and background regarding these estimates can be found in Appendix A.

How are elasticities and the resulting load shifts calculated?

Elasticity of substitution is a measure of the consumer substitution responses to relative price changes. In regards to energy use, it is simply a measure of the degree to which a consumer shifts consumption from on-peak periods (when the price is higher) to off-peak periods (when the price is lower).

Elasticities of substitution are calculated based on the natural logarithm of the ratios of on-peak to off-peak consumption with and without (or "before" and after") Time-of-Use (TOU) price signals as well as the ratio of the TOU prices. If the elasticity of substitution, the ratio of consumption before, and the ratio of the prices are all known, the new ratio of consumption after (i.e., with TOU prices) can be calculated. Knowing the before and after ratios of consumption, a simple calculation takes it one step further to determine the total amount of energy that is shifted.

The formula for elasticities of substitution is as follows:

$$ln(R_{AFTER}) = ln(R_{BEFORE}) - elasticity\ of\ substitution * ln(Price\ Ratio)$$

Where, R_{BEFORE}, and R_{AFTER} denote the ratio of consumption with and without TOU prices

As an example, assuming an on-peak to off-peak ratio of consumption of 3 to 1 before the introduction of TOU prices, a price ratio of 2 to 1, and an elasticity of substitution of 0.1.

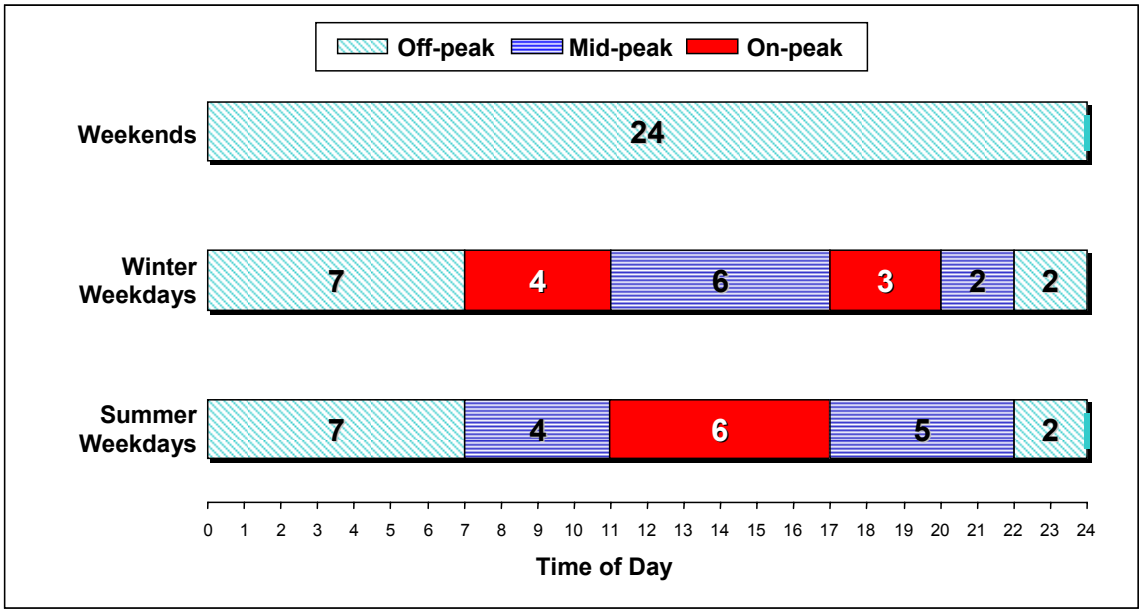
$$ln(R_{AFTER}) = ln(3) - 0.1 * ln(2)$$

The resultant ratio of on-peak to off-peak consumption with TOU price signals would be 2.8 to 1.

Potential TOU Prices for Smart Meter Customers

The time-of-use (TOU) price structure was assumed to be that given in the Ontario Energy Board's Regulated Price Plan (RPP) Manual, as shown in Figure 22.

Figure 22: Time Periods for TOU Price Signals



Source: Regulated Price Plan Manual, Ontario Energy Board, March 11, 2005

The RPP TOU prices for the initial RPP period starting April 1, 2005 are related to each other in approximately a 1 / 2 / 3 ratio. That is, mid-peak prices are approximately double the off-peak

prices and on-peak prices are approximately triple the off-peak prices. We used this same 1 / 2 / 3 price ratio in our analysis.

4.4.3 Load Shape Impacts

Residential load shape impacts for time-of-use (TOU) price signals are presented in the sections below, followed by commercial impacts for the same price signals. The following load shapes are representative of 2015 demand levels. Demand has been scaled up from the 2006 load shapes presented earlier in this report based on the July 2005, IESO 10 Year Outlook median growth scenario (roughly 0.88% per year)

In addition to the shift of consumption from on-peak to off-peak periods, higher prices during on-peak periods would also be expected to provide an elasticity-driven conservation impact. This conservation impact would be incremental to the impact of other conservation programs and energy efficiency standards that have already been reflected in the sector load shapes. For conservatism, Navigant Consulting has not reflected this potential impact in its analysis.

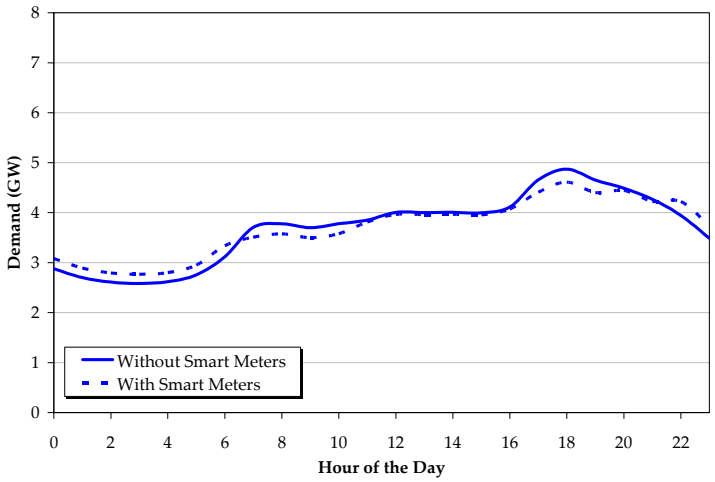
Impact on Residential Load Shape

Based on the residential load shape, expected TOU price ratio and elasticity estimates discussed above, the impact on the residential load shapes was estimated. The results are presented below.

The "with smart meters" load shape shown in Figure 23 represents Navigant Consulting's estimate of the likely medium-term impact from TOU prices applied to residential customers with smart meters in January. This impact could be expected to be realized gradually over a five year period from the initial installation of smart meters.

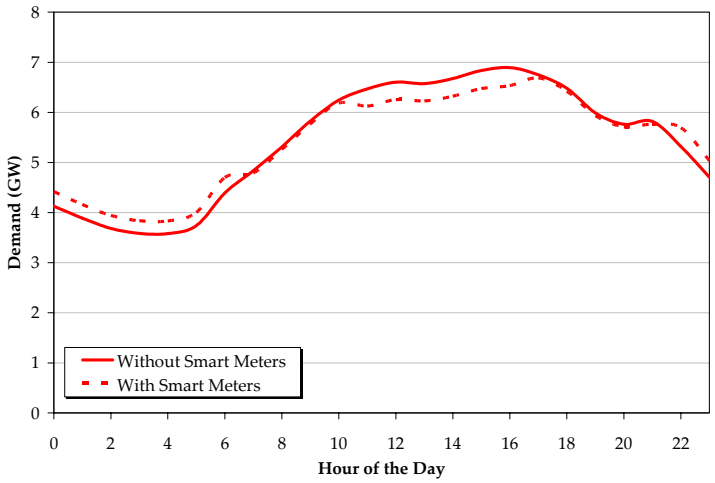
In the medium-term, smart meter implementation is forecast to reduce residential on-peak demand during a typical winter by roughly 5% or 300 MW from its previous peak at 6 pm.

Figure 23: January Residential Profile with and without Smart Meters and TOU Rates



As shown in Figure 24, residential on-peak demand during a typical summer day is forecast to drop by roughly 2% or 380 MW from its previous peak at 4 pm by 2015.

Figure 24: July Residential Profile with and without Smart Meters and TOU Rates



Commercial Load Shape Impacts

The "with smart meters" load shapes shown in Figure 25 and Figure 26 represent Navigant Consulting's estimate of the likely medium-term impact from TOU prices applied to commercial customers.

As shown in Figure 25, commercial on-peak demand is forecast to be reduced during a typical winter day by roughly 5% or 140 MW from its original peak at 5 pm. On a typical summer day, as shown in Figure 26, peak demand in the conventionally metered commercial sector is expected to be reduced by roughly 3% or 120 MW from its original peak at 1 pm.

Figure 25: January Commercial Profile with and without Smart Meters and TOU Rates

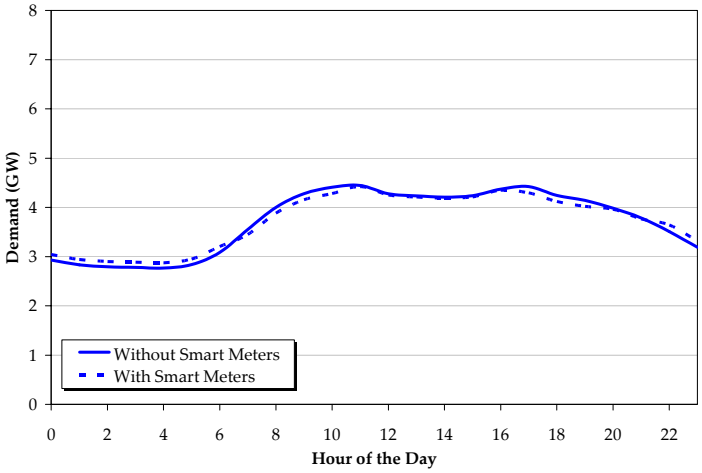
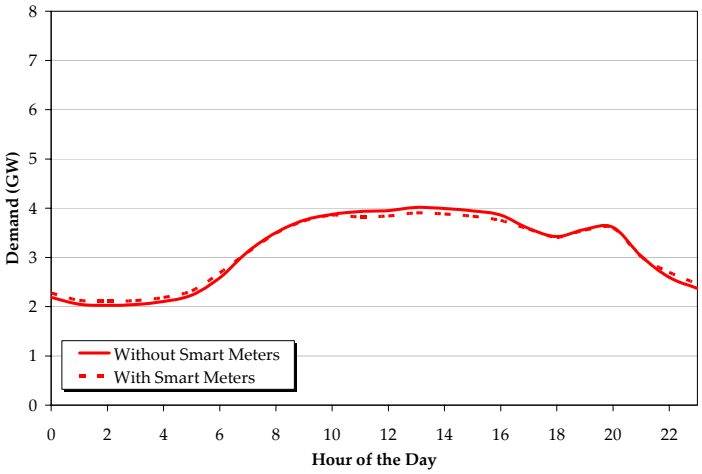


Figure 26: January Commercial Profile with and without Smart Meters and TOU Rates



Overall Impacts

The overall impact of TOU pricing was taken as the aggregate of the conventionally-metered commercial customers' and residential customers' load shifting present above.

The following figures present the forecast "before and after" aggregate Net System Load Shape profiles for January and July in 2015, when the full impact of the meters could be expected.

Figure 27: January Aggregate NSLS with and without Smart Meters and TOU Rates

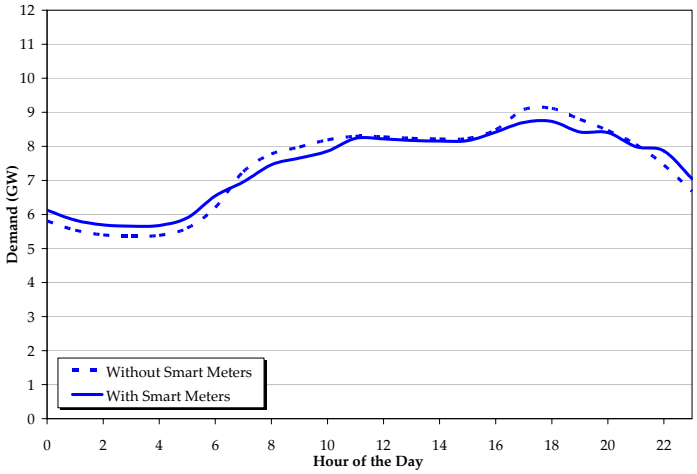
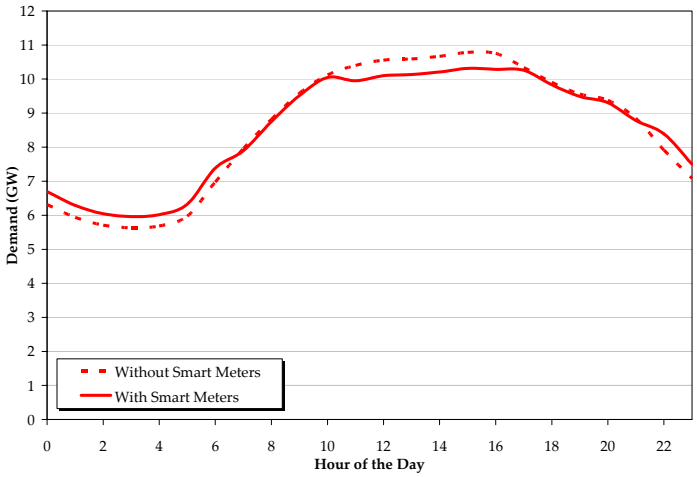
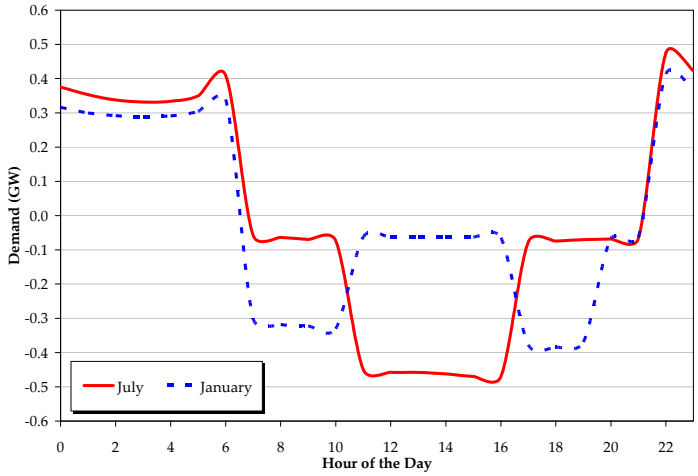


Figure 28: July Aggregate NSLS with and without Smart Meters and TOU Rates



Finally, the forecast energy shifted from peak to off-peak periods for a typical working weekday in January and July is presented in Figure 29.

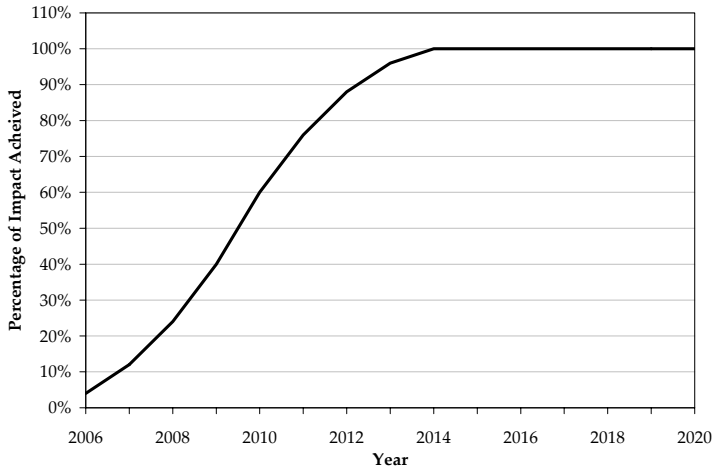
Figure 29: Hourly Load Shift Due to Smart Meters for a Typical January and July Day in 2015



4.4.4 Growth in Load Shifting Impact over Time

So far the results presented have only focused on a specific point in the future, 2015, at which time it is assumed the full potential, as well as total installation of the smart meters is realized. To meet the government's target, of a smart meter for everyone by 2010, NCL has assumed a constant installation rate of 20% per year from 2006 to 2010. The installation rate coupled with an expected gradual increase in customer response results in Figure 30, which shows the percentage impact in each year relative to a full impact.

Figure 30: Ramp-up to Full Benefit of Smart Meters for Base Case Elasticity



To calculate the system-wide reduction in peak demand, the energy shift in each hour of each year was adjusted based on the percentage of total impact achievable in each year (Figure 30, Table 15).

Table 15: Percentage of Full Smart Meter Impact Achieved in Each Year

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
4%	12%	24%	40%	60%	76%	88%	96%	100%	100%	100%	100%	100%	100%	100%

4.5 ONTARIO PROFILE ADJUSTED FOR CONSERVATION AND SMART METERS

Table 16 presents the forecast of Ontario peak demand 1) before conservation, 2) after conservation (based on the moderately aggressive conservation scenario – Aug 25), and 3) after the load shifting impact of smart meters, as well as the forecast demand reduction from conservation and smart meters on demand. Although the peak demand impacts for the other three conservation scenarios are different, the load shifting impacts for these other scenarios are similar in magnitude -- roughly 400 to 500 MW – after full effectiveness is achieved in 2014.

Table 16: Ramped Impact of Smart Meters on Ontario Load (Normal Weather)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Peak Demand (MW)										
Before Conservation	24,205	24,374	24,627	25,045	25,228	25,534	25,840	26,158	26,461	26,874
After Conservation	23,989	23,931	24,004	24,160	24,311	24,539	24,750	25,040	25,360	25,675
After Smart Meters	23,973	23,887	23,916	23,997	24,093	24,263	24,428	24,685	24,987	25,299
Impact (MW)										
Conservation	-216	-443	-622	-884	-917	-995	-1090	-1118	-1100	-1199
Smart Meters	-16	-44	-88	-163	-218	-276	-322	-354	-373	-376
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Peak Demand (MW)										
Before Conservation	27,211	27,552	27,898	28,248	28,602	28,961	29,324	29,692	30,064	30,441
After Conservation	25,959	26,292	26,634	26,992	27,375	27,767	28,162	28,568	28,978	29,400
After Smart Meters	25,535	25,814	26,151	26,504	26,883	27,270	27,660	28,062	28,466	28,883
Impact (MW)										
Conservation	-1252	-1260	-1264	-1256	-1227	-1194	-1162	-1124	-1086	-1041
Smart Meters	-424	-479	-483	-487	-492	-497	-501	-506	-512	-517

4.6 MODELLING OF WEATHER IMPACTS ON LOAD

Up to this point, the discussion and analysis surrounding the demand forecasts and load profiles has been based on static "normal" weather conditions. However, a rigorous economic analysis of the portfolios requires that they be evaluated under "actual" weather conditions. By failing to account for actual weather conditions that are likely to be experienced, peak demand may be understated. As a result the screening analysis would undervalue resources capable of providing peaking capacity.

One must expect that over the next twenty years Ontario will experience periods where temperatures are above normal as well as periods where temperatures are below normal.

Navigant Consulting has developed a methodology that, to the extent possible, evaluates the various portfolios under these conditions.

Consistent with the IESO's forecasting methodology, Navigant Consulting chose to use historic weather as an indicator of future weather conditions. Implicitly, this approach assumes that weather conditions from recent history are representative of weather conditions in the near future. Obviously, this approach will not reflect any long-term weather trends, but Navigant Consulting believes the use of historic weather is appropriate given the term of the analysis period.

4.6.1 Methodology for Modelling Impacts of Weather on Demand

The underlying methodology used by Navigant Consulting relies heavily on the approach used by the IESO for their load forecasting activities. The IESO approach is described in detail in the document entitled "Methodology to Perform Long Term Assessments", and is not discussed in detail here.[15]

The methodology for modeling the impact of weather on the typical week demand and conservation profiles involves four key steps:

- The first step was to develop "Historic Weather Weeks (HWW)". Each HWW contains within it, seven values. Each value represents an individual day of the week and the impact of that day's weather on energy consumption within the province.
- The second step involved the calculation of an average HWW for each month of the year. The Average Historic Weather Week (AHWW) was designed to correspond with the IESO's definition of "normal" weather and was used to determine the differential impact of weather outside of normal conditions.
- The third step involved the application of the weather impact, taken as the difference between the HWW and the AHWW, to the base demand profile.
- The final step is to use the same calculated weather impact, and apply it to the conservation decrement profile using a slightly different approach.

In the portfolio screening model, the final two steps are repeated for each iteration in the volatility analysis. For each iteration, a new random HWW is drawn for each month of the year for each year of the analysis period (ie, 12 months x 20 years = 240 weather "draws" per iteration) and a new weather impact is created.

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[15] Available on IESO website at: *http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2005jun.pdf*

4.6.2 Raw Data and Historic Weather Weeks

The main elements taken from the IESO methodology are the coefficients (Table 17) for each of the individual weather variables. In all, four weather variables are considered by the IESO: air temperature, humidity (measured as the dew point temperature), wind speed, and cloud cover. The coefficients represent the unit impact of the weather variables on daily energy consumption and form the basis for the development of the HWW. As an example, the coefficient for wind speed in the summer is 390 MWh – for each km per hour decrease in wind speed during a summer day energy consumption is expected to increase by 390 MWh.

Table 17: Weather Factors Affecting Daily Energy Demand[16]

Factors Affecting Daily Energy Demand			
Variable Class	Variable	Change in Variable	Impact On Daily Energy Demand (MWh)
Weather	Daily Avg Temperature		
	> 16º C	1ºC Increase	6,730 MWh Increase
	10ºC > and < 16º C	1ºC Increase	70 MWh Increase
	< 10ºC	1ºC Decrease	2,940 MWh Increase
	Daily Avg Humidity - Dewpoint		
	> 16º C	1ºC Increase	2,450 MWh Increase
	10ºC > and < 16º C	1ºC Increase	20 MWh Increase
	< 10ºC	1ºC Decrease	1,070 MWh Increase
	Wind		
	Summer	1 km/hr Decrease	390 MWh Increase
	Winter	1 km/hr Increase	160 MWh Increase
	Cloud		
	Summer	Decrease of 1 on Scale	1,080 MWh Decrease
	Winter	Increase of 1 on Scale	1,580 MWh Increase

Raw weather data for this analysis was obtained from Environment Canada for three weather stations, the relative weighting of each (Toronto 52%, Ottawa 31%, and Sarnia 17%) representing the majority of load within the province. The weather data was provided for each hour, and included data for each of the four variables considered by the IESO dating back 30 years to 1975.

For each month of the year a total of 99 HWW were developed. Only the weeks which were entirely contained within a single month were included. A sample of the historic weather weeks developed for the month of July are shown in Table 18.[17] The week circled with a solid line quite clearly shows the impact of consistently warmer temperatures. While in comparison, the week highlighted with a dashed line reveals the impact of warmer temperatures mixed with milder temperatures.

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[16] Source: IESO 10 Year Outlook; Demand Forecast July, 2005. http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2005jun.pdf

[17] Represent only the 6 most recent weeks in history at the time this report was developed.

The factors within each HWW represent the aggregate impact of the four independent weather variables on daily energy consumption in mega watt-hours.

Table 18: Example of Historic Weather Weeks Developed (units are MWh)

Week Starting	Monday 1	Tuesday 2	Wednesday 3	Thursday 4	Friday 5	Saturday 6	Sunday 7
7/12/2004	26,670	27,223	17,180	7,957	20,903	22,165	18,933
7/19/2004	22,438	25,346	34,158	31,829	-6,641	-43,481	8,869
7/4/2005	33,352	23,597	18,489	22,466	20,441	26,392	33,761
7/11/2005	41,568	41,852	39,868	35,002	36,772	33,050	33,926
7/5/2005	39,315	33,551	31,155	36,490	30,438	25,860	25,121
7/11/2005	39,432	24,872	11,405	19,394	19,749	19,937	23,164

4.6.3 Average Weather Impact

The typical week profile developed by Navigant Consulting and discussed earlier in this section is based on the underlying assumption of "normal" weather.

The coefficients provided in Table 17 are used by the IESO to develop the load forecast from the ground up. That is, there are meant to be applied to a forecast that does not contain any weather. As a result the HWW also represent the total impact of weather and not just the impact in relation to the norm. To correct for this, an AHWW was developed for each month. The AHWW was calculated as the average of the individual daily values for each of the HWWs in a given month. The AHWWs are shown in Table 19. The AHWW were designed to represent the normal weather impact inherent in the base demand and conservation profiles.

Table 19: Average Impact of Weather on Daily Energy Consumption (MWh)

Month	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
Jan	20,237	20,365	20,461	21,224	21,219	20,675	20,422
Feb	19,126	18,218	18,016	18,005	17,651	17,846	17,758
Mar	10,951	9,826	9,295	9,630	10,365	8,742	8,479
Apr	2,604	3,484	2,487	1,585	759	1,286	538
May	-3,487	-3,511	-5,524	-4,110	-4,530	-4,805	-4,306
Jun	2,920	4,232	3,649	2,197	2,833	4,163	5,426
Jul	11,108	10,468	9,411	9,410	8,377	8,874	10,626
Aug	8,330	7,434	8,545	7,100	6,798	5,920	5,507
Sep	1,179	1,376	-89	-308	-892	-522	-1,092
Oct	-2,814	-2,172	-467	-716	-1,337	-1,205	-474
Nov	6,450	6,948	6,958	7,265	7,797	8,078	8,470
Dec	14,883	15,384	15,563	16,034	15,800	15,316	15,709

4.6.4 Application of Historic Weather to Ontario Load Profile

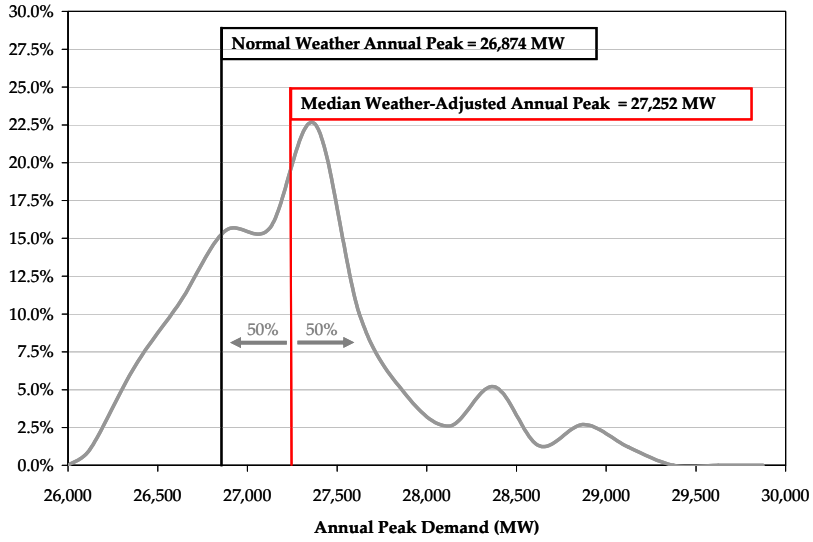
The modelling of weather impacts on demand was incorporated within the portfolio screening model's volatility analysis. As part of the volatility analysis the PSM selected one of the 99 HWW for each month of each year for the duration of the analysis period and applied it – based on the approach outlined below – to the base and conservation profiles.

Since the base demand profile from the IESO already reflects "normal" weather, each HWW is adjusted to reflect deviations from normal weather prior to being applied to the base and conservation profiles. This is done by taking the difference between the HWW and the AHWW.

The daily weather factors contained within the HWW now represent incremental energy consumption in a given day. This incremental energy is distributed across the day in proportion to the demand in each hour. During the summer months when air-conditioning load is the primary source of weather sensitive demand, the weather factor is applied across only the 16 on-peak hours. During winter months when heating load is the primary source of weather sensitive demand, the weather factor is applied across all 24 hours of the day.

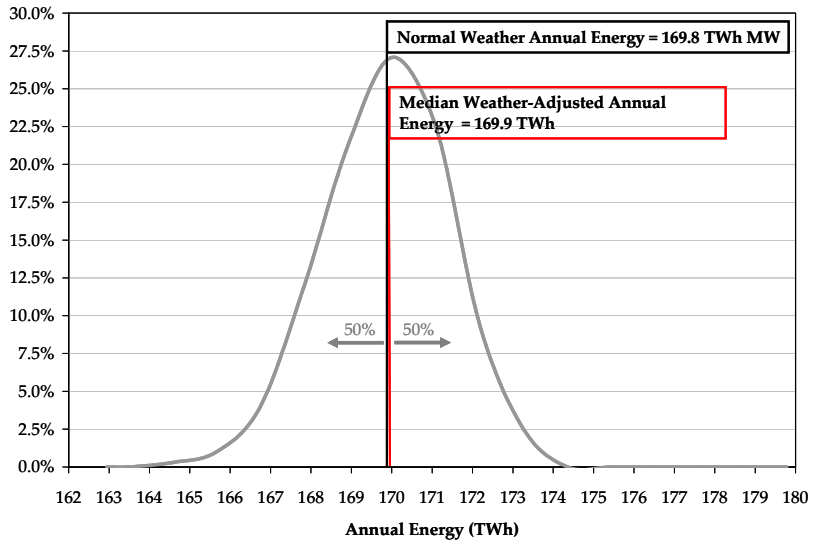
Over a significant number of draws (a draw involves the selection of an HWW for each month of the year and the application of it to the base demand profile), the median value of the annual peak demands and annual energy may be interpreted as typical weather forecast values. Figure 31 shows the distribution of annual peak demands in 2015 resulting from 1,000 weather draws. This distribution clearly illustrates that Ontario could experience weather conditions (either very hot or very cold weather) that would result in a peak demand that is significantly higher than the normal weather forecast. It also illustrates that the median peak demand is roughly 400 MW higher than demand based on the normal weather forecast. The median peak demand is what Navigant Consulting has termed as the "Typical Weather Peak Demand". Intuitively this makes sense. In general, Ontario is likely to experience at least one, if not more, hot or cold spells throughout the year. Depending on when these hot or cold spells arise, one would expect that peak demand would exceed any forecast that only reflects normal weather.

Figure 31: Impact of Stochastic Weather Modeling on Annual Peak Demand in 2015



While peak demand is highly sensitive to relatively short-lived weather conditions, variability in weather tends to average out over an entire year. Hence, the distribution of forecast annual energy will be much "tighter" than the distribution of peak demand. The modeling results bear this out – Figure 32 illustrates that the median annual energy of the weather adjusted profiles for 2015 is essentially the same as the normal weather forecast. There are instances where annual energy is higher or lower than the normal weather forecast, but for the most part these differences are relatively smaller in percentage terms that the differences in peak demand.

Figure 32: Impact of Stochastic Weather Modeling on Annual Energy in 2015



4.6.5 Application of Weather to CDM Impacts

As discussed previously, the conservation decrement profiles are based on "normal" weather conditions. Hence, just as the base profile is adjusted to reflect expected weather conditions, the conservation decrements are also adjusted.

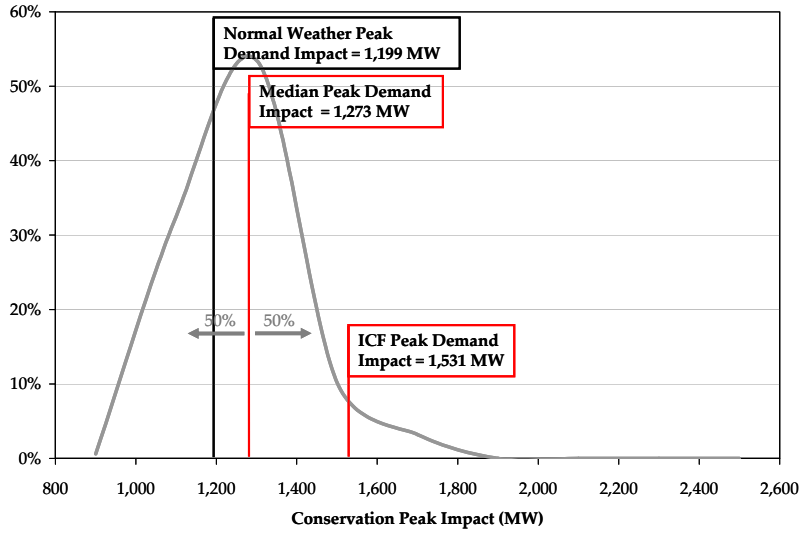
The primary source of weather sensitivity in the various conservation scenarios (and associated decrements) is improved air-conditioning efficiency (ie, reduced cooling load). For each of the four conservation scenarios, reduced cooling load represents a different proportion of the total decrement. In the very aggressive conservation plus standards scenario, reduced cooling load represents, on average, roughly 65% of the peak decrement. This value ranges from 35% in the moderately aggressive conservation scenario (Aug 25) to 50% in the remaining two scenarios.

The conservation decrements are adjusted in a slightly different manner than the base demand profile. To start, adjustments are only made in the summer months of June through September when air-conditioning load is greatest.

The adjustment to the conservation decrement is based on the incremental weather impact in base demand profile and the assumption that any change in the base demand profile due to weather is due to an increase in air-conditioning load. Hence, an increase in air-conditioning efficiency (as embedded in the conservation scenarios) will reduce the sensitivity of the base profile to weather. Ontario's average air-conditioning load during on-peak periods over the period from June through September is estimated to be approximately 3,000 MW. Based on this assumption, if the base profile was increased by 300 MW in a given hour due to the impact of weather, this would represent a 10% increase in air-conditioning load. If we know that 35% of the peak conservation impact (for the moderately aggressive scenario) is due to increased air-conditioning efficiency, then it is appropriate to assume that 35% of the conservation decrement will increase by 10% (ie, by 3.5%). Using this approach, the conservation decrement profiles are adjusted in a manner that best reflects their sensitivity to actual weather conditions.

Figure 33 shows the distribution of annual peak conservation impacts in 2015 for the same 1,000 weather draws discussed previously. In a 1 in 10 year hot summer the resultant peak decrement is within 75 MW of the ICF estimate. This margin of error is reasonable considering that a) 75 MW is only 0.25% of the forecast peak demand in 2015 of roughly 27,000 MW) and b) a 1 in 10 year "hot" summer would be less extreme than the summer of 2005, in which peak demand exceeded 25,000 MW on 53 occasions. Again the median (or typical weather) conservation peak impact is higher than the normal weather impact, for the same reasons as the median peak demand is higher than the normal weather peak demand..

Figure 33: Impact of Stochastic Weather Modeling on Conservation Peak Demand Impact



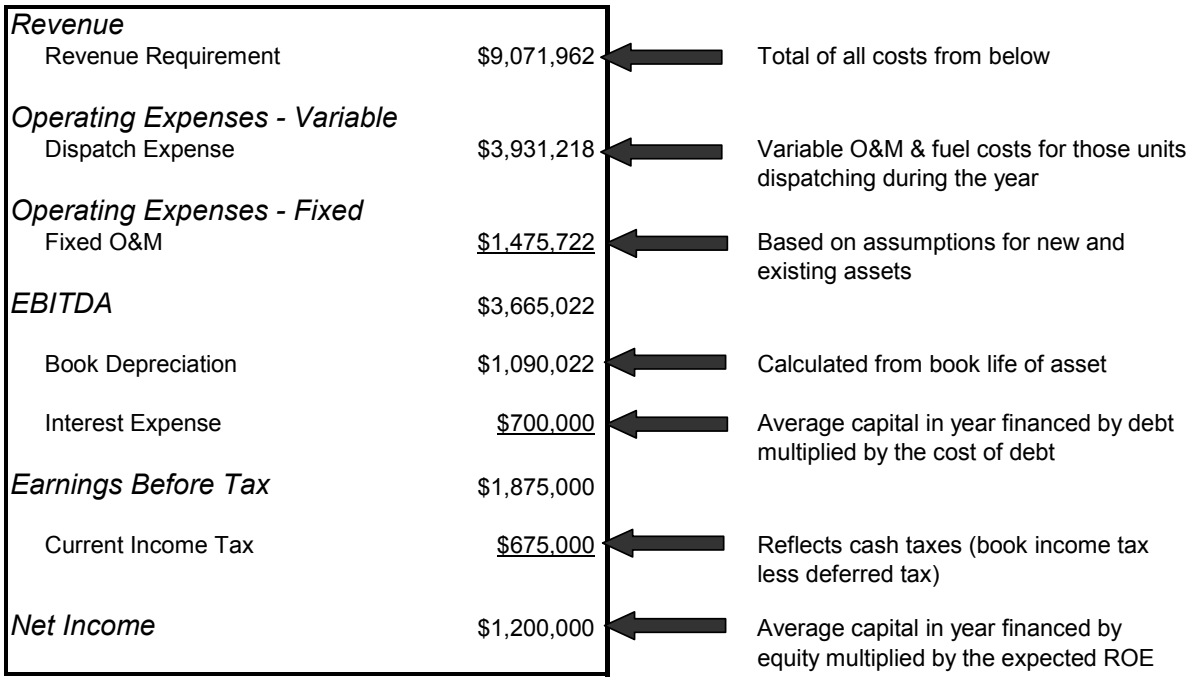
5 ECONOMIC AND FINANCIAL ASSUMPTIONS

The PSM relies on a number of economic and financial assumptions to generate the cost profiles of the portfolios reviewed by the OPA. These cost profiles are then summarized in the form of a present value figure of forecasted annual revenue requirements to create a reference point for comparing the various resource combinations from a cost to ratepayer perspective. The key assumptions and the reason for using revenue requirement as a benchmark are explained in further detail in this section.

5.1 REVENUE REQUIREMENT

Revenue requirement is a cost based approach typically used for regulated monopoly utilities to determine what an appropriate amount of revenue would be to meet a return on equity specified by the regulatory authority. This revenue amount is arrived at by forecasting all the costs associated with operating the utility, including all fixed and variable operating and maintenance expense, depreciation, interest on debt, taxes and the targeted return on equity.

Figure 34 - Illustrative revenue requirement calculation



The model calculates and annual revenue requirement for the portfolio of generating assets that is based on a return on and of capital employed, income taxes, and fixed and variable operating costs.

The revenue requirement approach assumes that, over the long term, owners of generating facilities will need to receive adequate revenue to cover these costs to ensure a sufficient supply of generation resources will exist. The sources of revenue could be through spot market sales, bi-lateral contract sales with third parties, power purchase or tolling agreements with the government, an installed capacity market or any combination of these sources of revenue.

Annual revenue requirements are then discounted by a pre-tax weighted average cost of capital over the forecast period of 20 years to arrive at one figure that can be compared between various portfolios. The model has the ability to include or exclude a terminal value when discounting the annual revenue requirements. The terminal value calculates the value of a perpetuity using the average of the final three years of revenue requirement divided by the discount rate.

5.2 CAPITAL STRUCTURE AND COST

Capital employed to construct new generation facilities or refurbish existing facilities is assumed to adhere to normal commercial financing requirements in terms of capital structure and expected return. Rather than develop assumptions for each technology, the PSM uses assumptions for capital structure and financing costs that are based on a blended portfolio of different resource technologies and financing sources. New or refurbished nuclear projects are likely to be associated with lower leverage and higher expected equity return to reflect the additional uncertainty associated with construction times and cost as well as the extended period of negative cash flow. However, other more proven technologies such as CCGT, SCGT, wind and most hydro projects would be associated with higher leverage and lower expected equity return. In addition, it is likely that some projects would be owned by income trusts that offer much higher leverage and lower financing costs. The overall assumptions for capital structure and cost are presented below:

Table 20 – Capital Structure and Cost of Capital

	Weighting	Nominal Cost
Debt	50%	7%
Equity	50%	12%

These capital assumptions, which are assumed to remain constant throughout the forecast period, are then used to estimate the financing costs portion of the annual revenue requirement. Net income after tax is calculated using the following formula:

NIAT = Average Capital Employed x % Financed by Equity x Expected ROE

Interest financing charges are calculated in a similar manner using the following formula:

Interest Cost = Average Capital Employed x % Financed by Debt x Cost of Debt

Net income and interest charges will tend to grow over the forecast period as new units are added to the portfolio of resources (capital associated with existing units is not considered as explained later in this section).

5.3 TAX TREATMENT

As of early fall 2005 when the PSM was constructed, the federal tax system included various enhanced tax incentives to encourage investment in efficient and renewable electricity generation technologies. Given that the calculation of revenue requirement in the PSM includes estimated cash taxes paid, it was important to properly capture the differing capital cost allowance ("CCA") rates between the various technologies employed in the portfolios. Therefore, the PSM employs full book depreciation and tax depreciation schedules by technology[18] to quantify the impact of deferred taxes on overall revenue requirement.

The capital cost allowance rates used in the model are as described in the 2005 federal budget.

Figure 35 - CCA by Technology

Technology	Capital Cost Allowance
CCGT	15%
SCGT	8%
Biogas	50%
Cogen	40%
Hydro	40%
Nuclear	8%
Wind	50%
IGCC	8%
Fuel Cell	50%

Certain technologies, such as hydro and cogeneration, have different CCA rates depending on either the capacity of the unit (hydro) or the heat rate of the overall generation process (cogeneration). Therefore, hydro and cogeneration are assumed to have a blended CCA of 40%

[18] Technologies with similar book life and CCA treatment are grouped together to reduce the size of the overall depreciation and tax schedules.

representing one half of the projects qualifying for the higher CCA rate of 50% and the balance qualifying for only the 30% CCA rate. While it is recognized that not all components of a generation plant will qualify for the accelerated tax depreciation rates, to minimize the complexity of the model while still capturing the tax advantages of certain technologies, the PSM assumes that all capital (by project) is subject to the same CCA rate. For example, most generation facilities will include a building which would subject to a different CCA rate than the generation equipment; however, for modelling purposes, all property, plant and equipment are subject to the same CCA rate.

Actual tax rates used in the model are based on the prevailing federal and provincial general corporate tax rates of 22.12% and 14% respectively for a combined tax rate of 36.12%. Capital taxes are not included in the model since both the federal and provincial governments have committed to phasing-out capital taxes by 2012 at the latest. The impact of including capital tax over the first six years of the 20 year forecast period would be immaterial.

5.4 RENEWABLE INCENTIVE CREDITS

The 2005 federal budget expanded and extended the Wind Power Production Incentive (WPPI) and established the Renewable Power Production Incentive (RPPI). The WPPI includes a production credit of $10 per MWh for the first ten years of production for those projects on-line prior to April 1st 2010. The PSM captures these production incentive benefits for wind farms and assumes that the program would be extended beyond 2010; however at a reduced production incentive of $8 per MWh. This sliding scale design is similar to the structure of the original program and an extension beyond 2010 seems reasonable given the political popularity of renewable incentives and the similar experience of the Production Tax Credit in the United States. The capacity eligible for the incentive was capped for each province under the original program; however it was not clear under the 2005 budget if the caps remain in place and when constructing the PSM, Navigant Consulting assumed that there is no limit on the MWs eligible for the incentive payment.

As of fall 2005 when the PSM was constructed, the RPPI had been proposed and the government had issued a discussion paper to help finalize the details of the program. Based on the discussion paper, the RPPI is designed to provide an incentive of $10 per MWh for the first ten years of production for those projects on-line between March 31, 2006 and April 1, 2011. The program has set an initial target of 1500 MW of new, renewable energy electricity-generating capacity, and Ontario is limited to 450MWs of qualifying capacity. However, in constructing the PSM, Navigant Consulting assumed that this cap will be adjusted upward or removed in future such that there is no limit on qualifying facilities in Ontario. Similar to the WPPI, the PSM captures these production incentive benefits for renewable projects and assumes that the program would be extended beyond 2010; however at a reduced production incentive of $8 per MWh.

5.5 CARBON EMISSIONS TAX

The PSM includes the ability to capture the financial impact of a carbon tax on the emissions of each portfolio. The structure of the carbon tax is based on the article in the July 16, 2005 issue of the *Canada Gazette* (v.139, no.29) entitled "A Notice of Intent to Regulate Greenhouse Gas Emissions by Large Final Emitters". The article outlined the expected carbon pricing structure to be established, the critical components of which are:

- The government has provided a price assurance of $15 per tonne based on intensity targets for large final emitters, including coal or natural gas
- The Notice of Intent states that firms are to reduce their emissions intensity by 15% against a 2010 business-as-usual forecast. Based on the proposed emissions intensity reduction and the 2010 forecast published in Canada's Emission Outlook, the following intensity targets have been included in the PSM:
    - A coal emissions intensity target of 865kg per MWh
    - A natural gas emissions intensity target of 256kg per MWh

The PSM distinguishes between coal and natural gas carbon emissions and all emissions over these intensity thresholds are assumed to be taxed at the $15 per tonne amount. The PSM also has the ability to tax all carbon emissions for sensitivity testing purposes.

5.6 TREATMENT OF EXISTING ASSETS

The book value of existing assets has not been factored into the model for a number of reasons. Firstly, it would be very difficult to obtain accurate information of the book value for existing assets in the province. While some owners do disclose the gross and net asset value of their total generating plant in Ontario, there is little disclosure on net generating assets segmented by technology type. Secondly, there is essentially no disclosure on the tax position or un-depreciated capital cost of these assets. Thirdly, and perhaps most importantly, the book value of existing assets will be identical for all portfolios reviewed. While the retirement date of certain units may vary in the different portfolios reviewed, in reality, the return on and of capital associated with these assets through customer rates is likely to continue whether the asset operates or is shut down early. (i.e. the owner is likely to be compensated for any asset that may be stranded).

6 RISK ANALYSIS

Introduction to Risk Analysis

Analyzing risk and uncertainty is certainly not a contemporary concept. The modern concept of risk is rooted in the Hindu-Arabic numbering system that reached the West nearly 800 years ago, however it was during the Renaissance period that serious study of risk emerged. Pascal, with the help of another brilliant mathematician named Pierre de Fermat, made the first breakthrough in probability theory in 1654, and by 1725 mathematicians were competing with each other to develop life expectancy tables used to determine the premiums of life annuities sold by the English government to finance itself. The marine insurance industry was flourishing by the mid 1700s, requiring the sophisticated use of risk analysis methods.

With the advent of new discoveries and mathematical methods, the world of risk analysis and assessment developed and matured. By 1875, regression analysis to the mean was discovered and brought with it the expectation of normal matters (distributions) regarding world states. Building upon these theories, in 1952 Nobel Laureate Harry Markowitz demonstrated mathematically why putting all your "eggs in one basket" is unacceptable from a risk management perspective and why diversification is the key to risk mitigation. Markowitz's Modern Portfolio Theory (MPT) revolutionized Wall Street, corporate finance, and decision making under risk and uncertainty, and remains a fundamental element of risk assessment and mitigation today.

Markowitz demonstrated that if we treat single-period returns for various securities as random variables, we can assign them expected values, standard deviations and correlations. Based on these, we can calculate the expected return and volatility of any portfolio constructed with those securities. Volatility and expected return reflect proxy's for risk and reward. Out of the entire universe of possible portfolios, certain ones will optimally balance risk and reward. These comprise what Markowitz called an efficient frontier of portfolios, and investors or decision makers should select a portfolio that lies on the efficient frontier. This frontier can be plotted as a risk/reward matrix that demonstrates the risk (plotted on the y axis) and reward (plotted on the x axis). Portfolios can then be plotted against each other to visually observe the risk/reward trade-off that Markowitz demonstrated mathematically.

Since Markowitz introduced MPT, others have expanded the application to include leverage and risk-neutral methods but the principals of MPT provide a broad context for understanding the interactions of systematic risk and reward. It has profoundly shaped how institutional portfolios are managed, and the mathematics of portfolio theory is used extensively in financial risk management and was a theoretical precursor for today's value-at-risk measures.

For the purposes of resource planning, the concept of the risk-reward trade-off is altered slightly to a concept of trading off the risk of a portfolio for the expected cost of the portfolio. The application of risk measurement techniques is greatly complicated by the issues presented by electric markets. Sophisticated mathematical analysis is required to quantify risk in sufficient richness for the types of risk vs. cost decisions demanded by the power supply and DSM situation in Ontario.

Defining Risk, Uncertainty, and Exposure

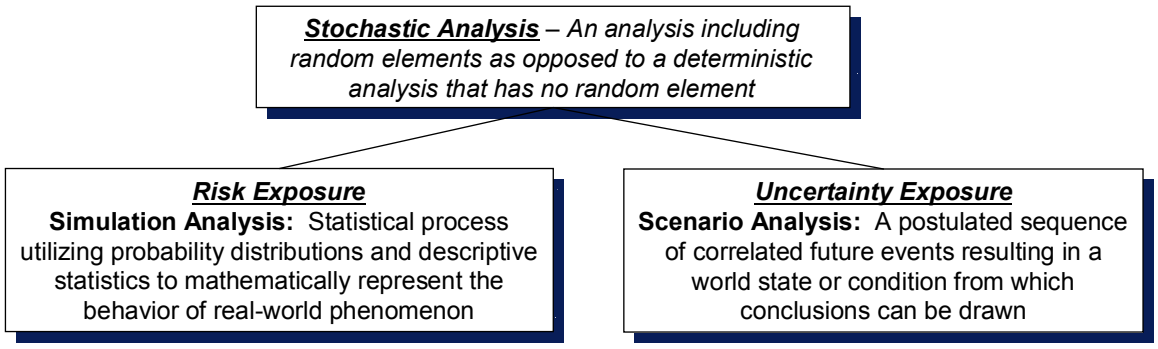
For purposes of developing the risk framework applied to the Ontario Power Authority's Supply mix Analysis, some definitions are appropriate. In his treatise entitled Risk, Uncertainty, and Profit, Frank K. Knight made perhaps the first distinction between risk and uncertainty, and this distinction is critical to the appropriate application of analysis tools and methods in the context of a resource analysis effort. Risk refers to situations where the decision-maker can assign mathematical probabilities to the randomness of outcomes faced. Uncertainty refers to situations when randomness cannot be expressed in terms of specific mathematical probabilities. Exposure is the extent to which a set of risks or uncertainties can bring hazard or harm. For the purposes of this Supply mix Analysis, exposure is the extent to which a set of risks or uncertainties bring harm to the performance of the resource portfolio under evaluation.

Analysis Techniques

The Supply Mix Analysis employed three techniques in analyzing exposure to the risk and uncertainty associated with the various resource portfolios considered; these included simulation, scenario, and sensitivity analysis. Each method utilizes a different framework and processes to measure exposure to risk and uncertainty. In assessing risk we are interested in potential future outcomes given our assumptions about the future, which are treated as random. To model these, we specify a stochastic process based upon the time series we are interested in modeling. The word stochastic means random, and a stochastic process is a set of random variables that are ordered with respect to time. If time or variables take on integer values, the process is a discrete process. If it takes on real values, it is a continuous process.

For some world states, a continuous process is optimal since the variables can take on an infinite number of ranges (e.g. natural gas prices) whereas in others the range is discrete (e.g. a carbon tax will/will not be assessed). Both circumstances require a stochastic method to describe risk and uncertainty, as illustrated in below:

Figure 36 - Stochastic Analysis for Risk and Uncertainty


Stochastic Analysis – An analysis including random elements as opposed to a deterministic analysis that has no random element
Risk Exposure
Simulation Analysis: Statistical process utilizing probability distributions and descriptive statistics to mathematically represent the behavior of real-world phenomenon
Uncertainty Exposure
Scenario Analysis: A postulated sequence of correlated future events resulting in a world state or condition from which conclusions can be drawn

For randomness that is able to be represented mathematically, simulation analysis is the most appropriate. There are multiple frameworks through which mathematically describable stochastic analysis can be applied. One method with a long history involves "decision tree" analysis, which seeks to demonstrate potential outcomes given the random movement of key variables. Although founded upon probability theory, tree analysis reflects poor probability representation and affords minimal descriptive statistical parameters. Additionally, it is not able to fully utilize correlated variables and is not representative of "real-world" or continuous systems. Other numerical methods such as the Black-Scholes model provide important insights into valuation, but fall short in providing detailed descriptions of risk and uncertainty, and can be very difficult to implement appropriately.

Simulation has replaced numerical solutions (or closed-form solutions) as a superior analysis technique and is a preferred method for stochastically measuring risk. Through simulation of multiple outcomes given ranges in which the random variables can be expected to fluctuate (volatility or standard deviation) and the level of correlation, if any, resulting between the movement of one or more variables on the remaining variables, simulation results demonstrate a comprehensive set of statistical and risk information when aggregated.

Until the recent proliferation of high-speed computer technology, it was too time intensive and analytically difficult to perform simulation analysis to a level that would sufficiently support a comprehensive risk analysis of a broad set of resource portfolios. Advances in computer technology have changed this, allowing large numbers of iterations with the movement of multiple variables to be simulated relatively quickly. Results, rather than being presented on an individual or deterministic basis, are presented in terms of frequency distributions and statistical descriptors, providing summary statistics describing the aggregation of outcomes based upon the correlated fluctuations of multiple parameters.

Since some randomness cannot be expressed through mathematical probabilities, the appropriate tool to use is scenario analysis. Scenario analysis represents the assessment of exposure based upon the discrete outcome of a particular world state through the direct manipulation of a

combination of correlated variables. The process of developing world states can be very subjective and relies on the technical expertise of the individuals involved in developing the scenarios. Scenario analysis is, however, a critical tool when considering uncertainties or discrete stochastic processes.

Sensitivities represent discrete changes to individual variables to determine the impact on value or risk. Such changes may include varying the price of natural gas, or the rate at which load grows in the Province. Sensitivities are conducted through a deterministic, or single-outcome methodology and provide the means to bound risk within a specified parameter (e.g. high or low prices).

Through the use of simulation, scenario analysis, and sensitivity analysis, the Ontario Power Authority has performed a comprehensive stochastic analysis to quantify the exposure of various resource expansion plans to risk and uncertainty. The development of the parameters used in the stochastic process, and the analyses performed, are described herein. These parameters define the fundamental drivers that underlie the Supply Mix Analysis.

6.1 MONTE CARLO SIMULATION

6.1.1 Variables Selected

A wide range of variable were considered in the supply mix analysis. A small, but significant subset of these variables were considered risk variables in the context of the simulation analysis performed on the various resource portfolio candidates. Through a series of sessions with OPA staff and external consultants a list of key risk variables was developed and is as follows:

- Natural Gas prices
- Residual Oil prices
- Coal prices
- Uranium prices
- Load forecast
- Capital cost of resource technologies
- Hydro availability
- Forced outage rates

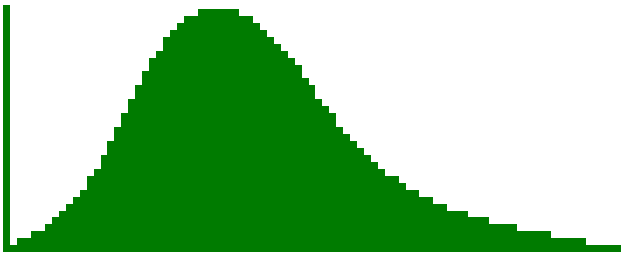
This list is not meant to be comprehensive, but is intended to be robust given the time constraints associated with developing the Supply mix Analysis. As the analysis is broadened in the context of the forthcoming Integrated Resource Analysis, these variables and the descriptive parameters associated with will be augment and refined as appropriate.

The distributions applied to each variable are outlined in Appendix B

6.1.2 Distribution Types

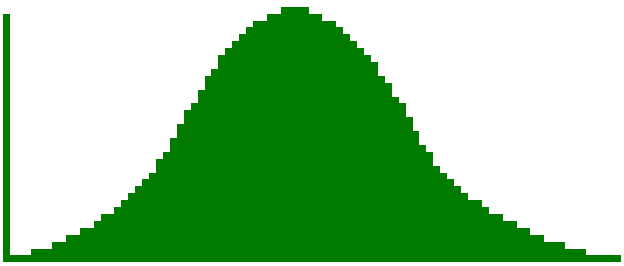
While there are multiple types of distributions that describe data and events, historical analyses of commodity price behavior reflect lognormal distributions of data. Lognormal distributions are observed in situations where values are positively skewed from the mean, but cannot become negative. Commodity prices tend toward lognormal distributions since infrequent but extreme price spikes create tails that are positively skewed and commodity prices do not fall below a value of zero (for any significant period of time). The Supply mix Analysis utilized a lognormal distribution to describe the coal, natural gas, oil, and nuclear fuel pricing. The figure below is an example of the profile of a lognormal distribution.

Figure 37 – Lognormal Distribution Profile



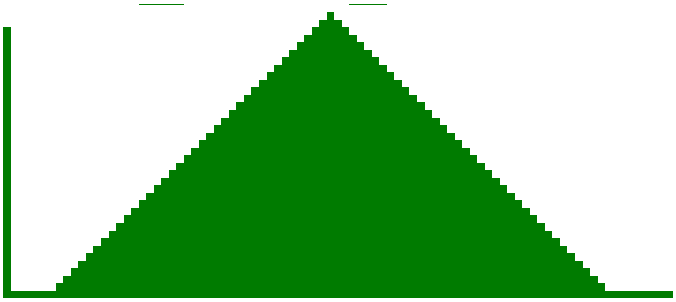
Normal distributions are observed in natural phenomena where values are most likely to be clustered around the mean with marginal extreme values occurring equally to the positive and negative side of the mean. The Supply mix Analysis used normal distributions to describe load growth volatility due to economic growth and variation in forced outage rates associated with thermal generation technologies. The use of normal distributions to describe variables such as load growth and forced outage rates reflect the reality that these estimates can move equally in either direction of their respective mean values. The figure below is an example of the profile of a normal distribution.

Figure 38 - Normal Distribution Profile



Triangle distributions are utilized when historical data is sparse, or unavailable. If the maximum/minimum of a distribution can be determined through observed data or developed subjectively, a triangle distribution can be employed. Triangle distributions may be symmetrical or skewed either positively or negatively around the most likely value. Triangle distributions have been used for the variation in hydro availability due to weather and for variation in capital costs. The figure below shows the profile of a symmetrical triangle distribution.

Figure 39 - Triangle Distribution Profile



Please refer to Appendix B for the precise distribution used for each variable.

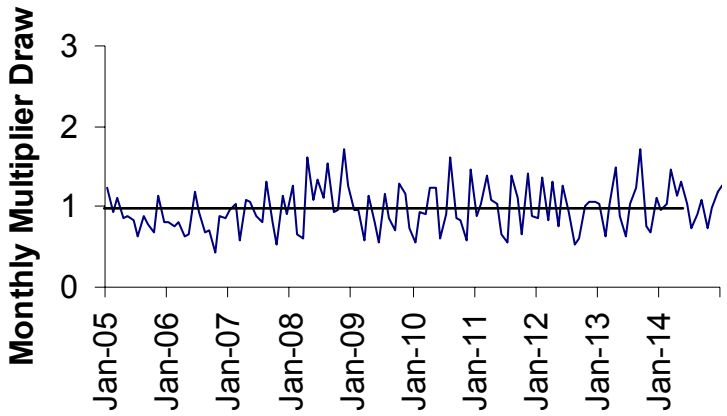
6.1.3 Variance Parameters

There are three variance methods that can describe commodity prices; constant variance, random walk, and random walk with mean reversion. Each of these variance methods is discussed in detail.

Constant Variance

Constant variance reflects the standard deviation of the mean. For each random iteration, the draw starts at the mean and as a result there is no inter-period relationship between iterations. Values tend to fluctuate around the mean in a constant pattern over time, reflecting an equal probability of movement up or down over time depending on the distribution shape, but with no directional tendency. The resulting draws associated with constant variance tend to be generally choppy and are inconsistent with commodity price behavior over extended periods of time. Constant variance is most applicable for naturally occurring phenomena where the expected value is more likely to be closer to the mean than extreme values. The figure below illustrates results utilizing a constant variance parameter:

Figure 40 - Constant Variance Profile



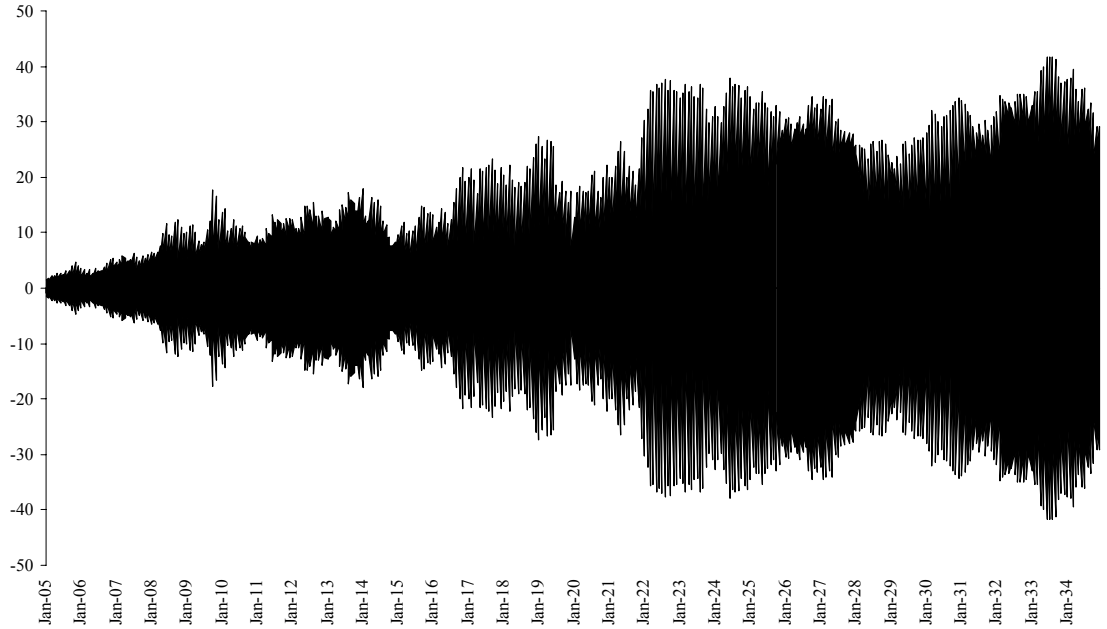
The constant variation technique was employed with the following variables:

- Forced Outage rates
- Load growth due to economic growth
- Hydro availability due to weather fluctuations

Random Walk Variance

Random walk variance reflects the characteristics of Geometric Brownian Motion (GBM), where each iteration in the random draw process begins with the previous period value rather than the mean value. A GBM, or exponential Brownian motion, is a continuous-time stochastic process in which the logarithm of the randomly varying quantity follows a Brownian motion, or, perhaps more precisely, a Wiener process. It is appropriate in mathematical modeling of some phenomena in financial markets and is used particularly in the field of option pricing because a quantity that follows a GBM may take any value strictly greater than zero, and only the fractional changes of the random variable are significant. The chart below depicts the characteristics of GBM over time. As illustrated in the figure below, the variance continues to expand with time, reflecting the nature of constant volatility that compounds over time.

Figure 41 - Illustration of Geometric Brownian Motion Price Profile

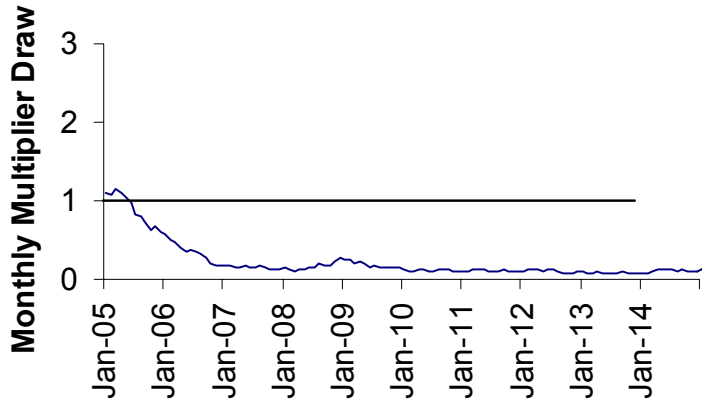


While this is precisely the nature of stock prices, it does not reflect the nature or historical behavior of commodity pricing over the long term. The variation of commodity prices through time does not reflect the wide diffusion of variance over time that GBM demonstrates, but rather tends to follow a reversion to mean characteristic.

Random walk variance is demonstrated as calculated volatility, rather than as a standard deviation from the mean (constant variance). Volatility is a measure of uncertainty about the movement of a variable over time, and is commonly stated as an annual number. The volatility of a variable can be defined as the standard deviation of the return observed by the variable in one year then the return is expressed using continuous compounding. Volatility is the standard deviation of the natural logarithm of the price or value of a variable at the end of one year, and is expressed as $\sigma\sqrt{\Delta t}$ (where σ is the standard deviation and t is the time interval).

Due to its limitations and tendency to over-estimate the impacts of constant volatility over time, the Supply mix Analysis did not utilize random walk variance parameters. The chart below demonstrates a single result under a random walk variance parameter. As illustrated, the next-period iteration begins at the previous iteration endpoint; creating a wide diffusion of results over a long time period.

Figure 42 - Random Walk Variance Profile



Random Walk with Mean Reversion Variance

Random walk with mean reversion reflects a variance parameter that seeks to incorporate the fundamentals of randomly occurring outcomes while staying within the framework of observable pricing behavior that is consistent with commodity market pricing behavior.

In 1999, Robert Pindyck, Professor of Economics and Finance at the MIT Sloan School of Management, published a white paper in The Energy Journal entitled The Long-run Evolution of Energy Prices, in which he described his analyses of historical commodity price movements and the suggested use of mean reversion variance parameters in forecasting energy prices.

As the impetus for his work, Pindyck attempted to explain energy prices in structural terms, i.e., in terms of movements in supply and demand, and the variables that determine supply and demand. He found that structural models were not always useful for long-run forecasting, and as a result, forecasts of energy prices over longer time horizons are often no more than extrapolations in which prices are assumed to grow in real terms at a fixed rate. The rate of growth might reflect some notion of resource depletion and/or technological change, and could follow a random walk process with some drift.

Alternatively, prices could be assumed to revert to a trend line that grows or declines over time, which would be consistent with the notion that commodities are produced and sold in competitive markets, so that prices should revert toward long-run marginal cost which are likely to change slowly and predictably over time. This theory would imply that price shocks are only temporary and over sufficiently long time horizons prices are random walking and mean-reverting rather than just random walking.

According to Pindyck, whether such approaches to long-run forecasting are reasonable depends on the stochastic process that the price follows. He examined the long-run behavior of oil, coal, and natural gas prices in the United States without any attempt at structural modeling, but rather

focusing on alternative time-series stochastic processes that might be consistent with this long-run behavior.

The concept of prices reverting to trends which move over time is not new. Boston University economics professor Pierre Perron developed a stochastic switching model in 1989 that allows for discrete shifts in the slope or level of the trend line. Applying this model to real GNP data, he found two events that seem to represent permanent changes in the underlying process, the 1929 Great Crash (which shifted the trend line downward) and the 1973 oil price shock (which changed the slope of the trend line).

Pindyck demonstrated that the behavior of real energy prices suggests reversion to trend lines with slopes and levels that are both shifting continuously and unpredictably over time, so that each price follows a multivariate stochastic process. The shifts themselves may be mean-reverting, but ignoring them is misleading, and can lead to suboptimal forecasts. To accomplish this task, he examined the real prices of crude oil and bituminous coal over a 127-year period from 1870-1996. Natural gas data beginning in 1919 was also examined. For each resource, he fit the log real price series to a quadratic time trend, first using all of the data in the sample, and then using data only through 1960, through 1970, and through 1980.

In each case he ran a regression of the log price on a constant, time, and time squared interval. Each fitted trend equation was used to forecast prices through the year 2000. These fitted trend lines (and the resulting forecasts) move considerably as the sample period to which they are fit is lengthened. Furthermore, he found that although the magnitudes of the shifts vary, there is no single point in time for any resource at which shifts can be exclusively localized.

These findings suggest two basic characteristics of long-run price evolution. First, the log real price of each resource seems to be mean-reverting to a quadratic trend line, although the rate of mean reversion is slow, taking up to a decade to occur. Second, the trend line itself fluctuates as the sample is extended.

Rather than focusing on tests to determine whether or not prices follow random walks, Pindyck thought it may be more informative to address the extent to which price shocks are temporary or permanent. He found that variance ratio tests are informative in this regard, and such tests are based on the fact that if price follows a random walk, then the variance of k-period differences should grow linearly with k. On the other hand, if price follows a mean-reverting process, the variance of k-period differences will approach an upper limit as k grows, so that this ratio will fall to zero as k increases. More generally, the ratio provides a measure of the extent to which price shocks are persistent, or equivalently, the relative importance of any random walk component of price.

Although OPEC succeeded in pushing oil prices above competitive levels for periods of time, over the long run oil production has been largely competitive. The same is true for coal and

natural gas. Pindyck indicated that he would expect the real prices of these resources to revert to long-run total marginal cost, i.e., a marginal cost that includes user costs associated with reserve accumulation and resource depletion. For a depletable resource such as oil or natural gas, he expects both the level of the log price trajectory and its slope to fluctuate over time in response to fluctuations in demand, extraction costs, and reserves.

Pindyck concluded from historic pricing data that for oil and coal any random walk component of a price shock is small, so that shocks are mostly transitory and indicates that this is consistent with a process in which price is mean-reverting.

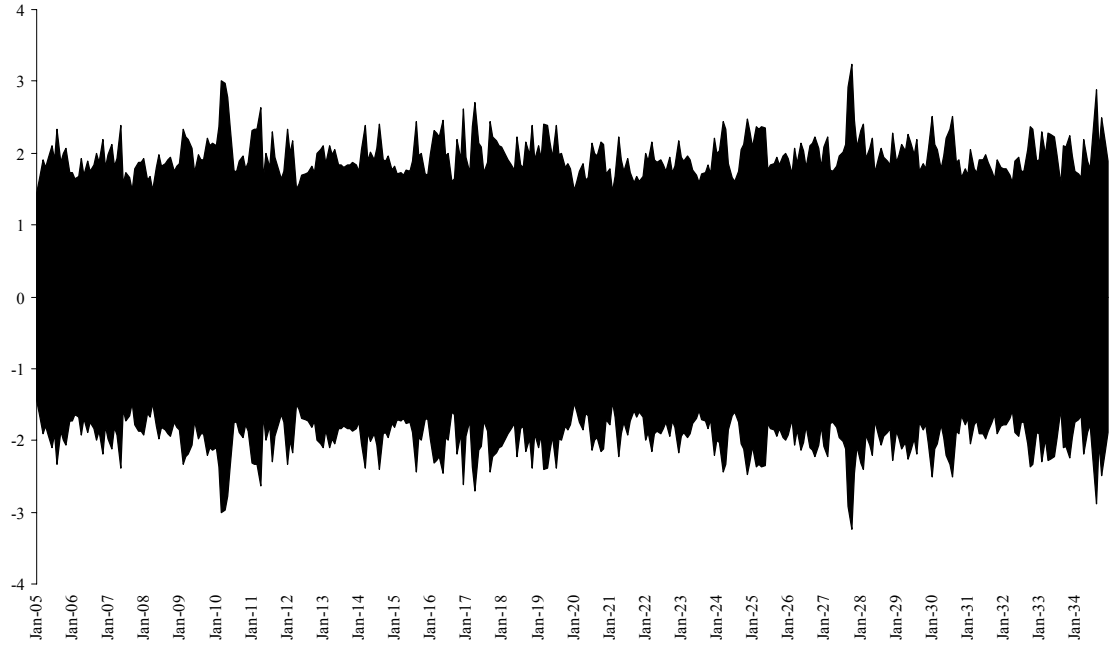
For natural gas, Pindyck found the results of using his model were inconsistent with both mean reversion and geometric Brownian motion processes. Pindyck suggests, however, that this pattern may simply reflect the shorter time series for these prices, along with the high degree of curvature of the quadratic trend line. He indicates that this is the case not so much because the earlier forecast data do not closely replicate more contemporary data, but more because the model does not describe movements in the trend lines for these commodities that are consistent with theory.

Pindyck points out that the inconsistency for natural gas pricing is likely due to the sensitivity of a filtering process which he applied in the initialization, and found that by using a different sample period, he was able to produce estimates that yielded better forecasts and were consistent with a mean reversion process. He suggests that the difficulties experienced with natural gas pricing may be due to problems of initialization and the sensitivity of the estimates to the first few data points. His estimates are significantly improved for both coal and natural gas when slight modifications to beginning sample dates are used. As such, he emphasizes that the promise of mean reversion models derives largely from the fact that they capture in a nonstructural framework what basic theory tells us should be driving price movements and is supportive of their application in forecasting.

From his analyses, Pindyck suggests that a model forecasting long-run commodity price evolution should incorporate two key characteristics: (i) reversion to mean production value which follows a trend; and (ii) continuous random fluctuations in both the level and slope of that trend.

The figure below illustrates a stochastic process incorporating GBM with mean reversion, clearly demonstrating that variation within the framework of mean reversion eliminates the compounding effects of continuous volatility diffusion (GBM) over time.

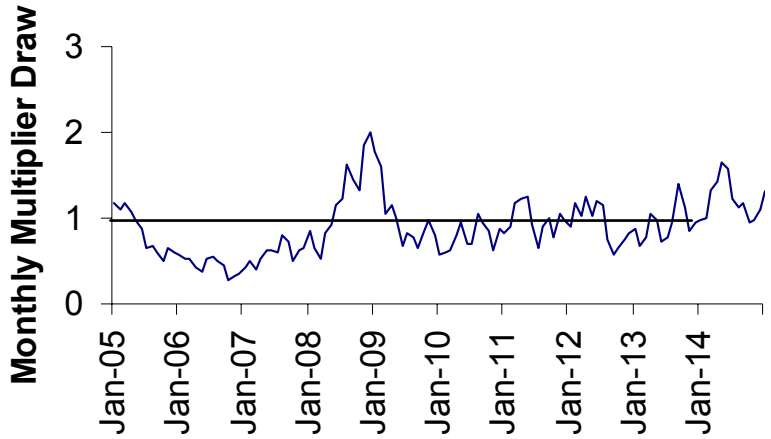
Figure 43 - Illustration of GBM with Mean Reversion Price Profile



Pindyck concludes that, for irreversible investment decisions for which energy and related commodity prices are the key stochastic state variables, (1) the GBM assumption is unlikely to lead to large errors in the optimal investment rule and (2) the actual behavior of real commodity prices over the past century imply that forecasting models should incorporate mean reversion to a stochastically fluctuating trend line. The combination of GBM with mean reversion provides a solid framework in which to forecast commodity prices.

In light of Pindyck's analysis and findings, the Supply mix Analysis has incorporated random walk (GBM) with mean reversion as the appropriate variance methodology to be applied to the certain commodities evaluated in the simulation. The chart below demonstrates results under a random walk with mean reversion variance parameter:

Figure 44 - Random Walk with Mean Reversion Variance Profile

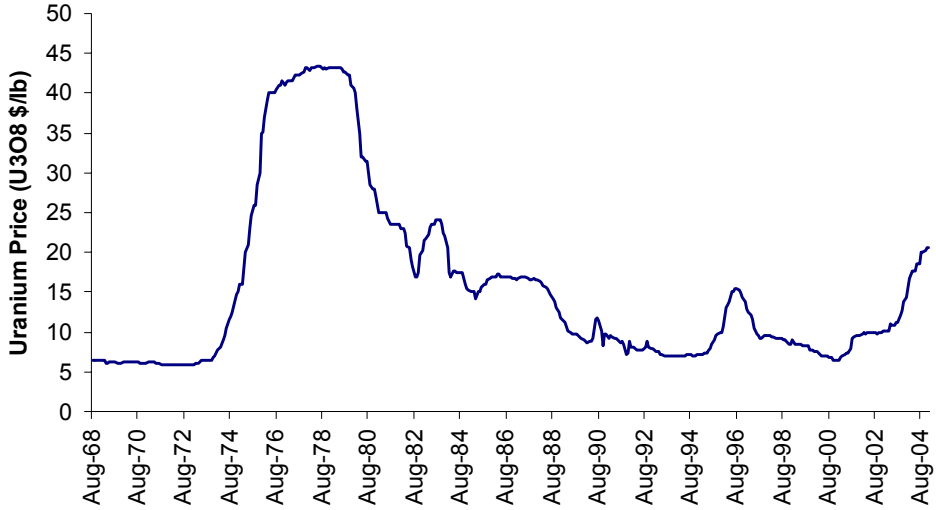


The random walk with mean reversion technique was used for the following variables in the Supply mix Analysis:

- Natural gas commodity prices
- Coal commodity prices
- Oil (No. 2 fuel oil) commodity prices
- Nuclear fuel commodity prices

The development of the descriptive variables of these four commodities relied on historical analysis of price data. The data associated with each of the historical price streams were from different sources and had different characteristics. The historical nuclear fuel price data was provided by the UX Consulting Company, LLC, a nuclear fuel consultancy. The nuclear fuel prices provided were from 1969 through 2004. The price data was for U_3O_8, an unprocessed ore. The historical prices were provided on a monthly basis and are shown in the figure below:

Figure 45 - Historical U_3O_8 Prices

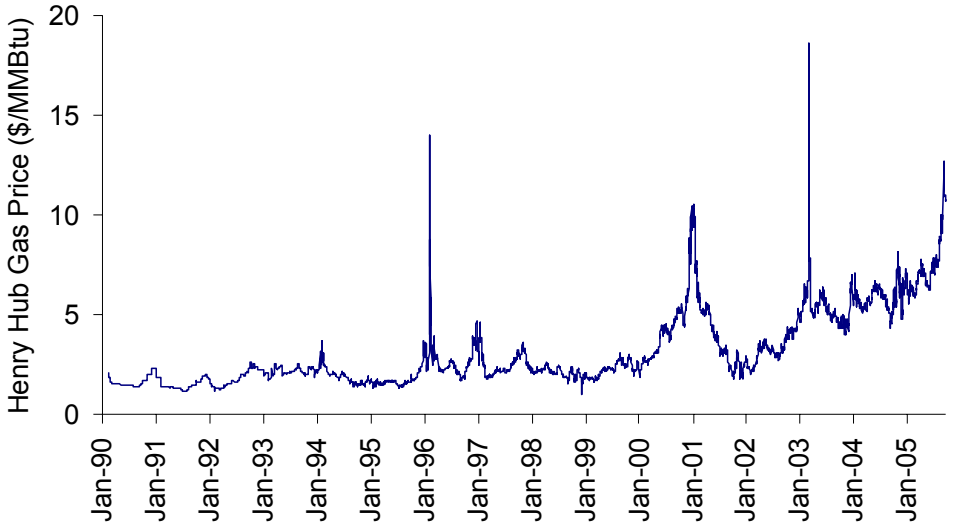


Source: UX Consulting Company, LLC

Analysis of this price stream quickly indicates a significant price spike corresponding to the crude oil crisis of the 1970's and the resulting dramatic spike in nuclear reactor orders in the US. For the purposes of the Supply mix Analysis, this price spike was considered an outlier and was removed from the data set used to develop the variance parameters. The period used to develop the parameters was from 1985 through 2004.

The natural gas prices used to develop the variance parameters was taken from historical Henry hub prices. Henry Hub has the most robust and complete historical data available (basis differential were used to convert these gas prices to Dawn Hub natural gas prices for forecasted values). Data from January 1990 through September 2005 were analyzed to develop descriptive statistics. The following figure shows the historical data for natural gas.

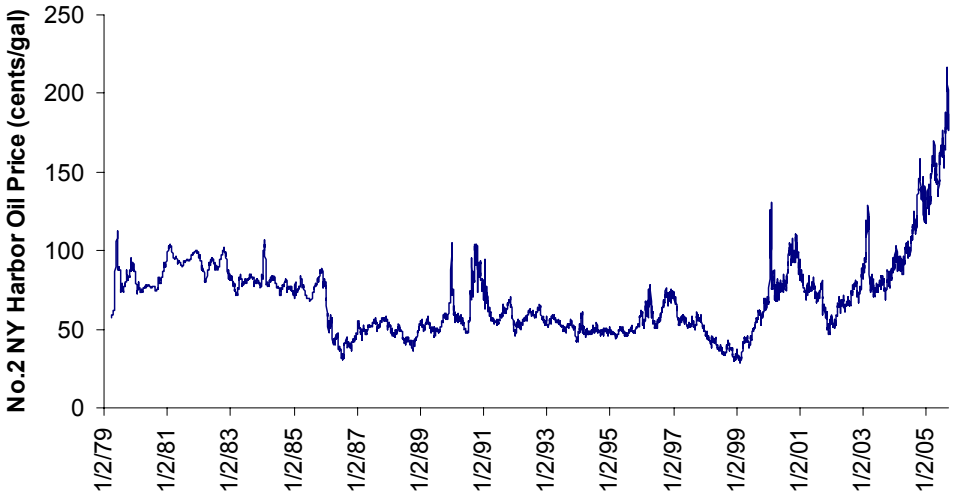
Figure 46 - Historical Henry Hub Natural Gas Prices



Source: Bloomberg Financial

The oil prices used to develop the descriptive statistics were taken from New York Harbor #2 Fuel Oil historical price data. The period of prices used in the evaluation included 1979 through September 2005 as shown below.

Figure 47 - Historical NY Harbor #2 Fuel Oil Prices



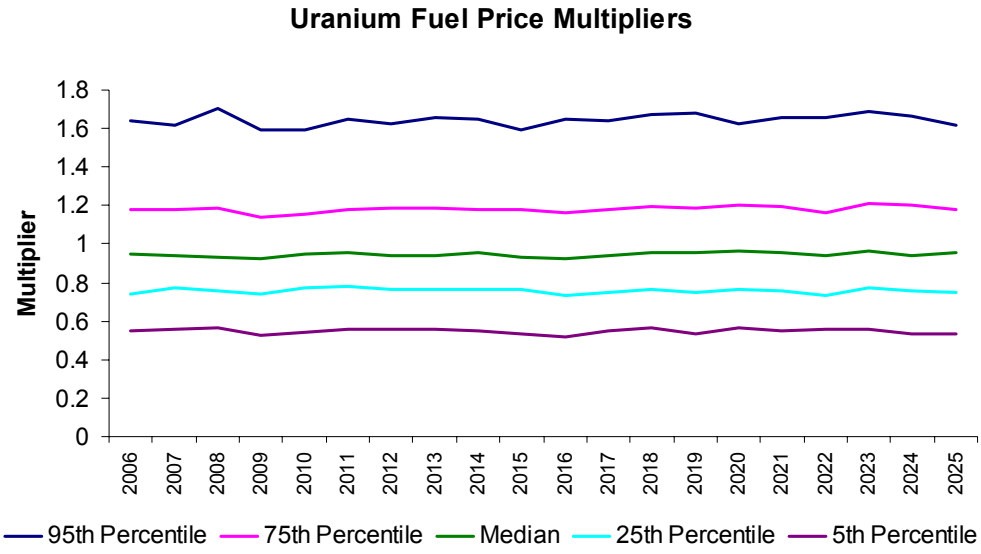
Source: Bloomberg Financial

The coal prices used to develop the descriptive statistics were taken from the Big Sandy Mid-Appalachian Basin Hub. The contract at the hub is for 12,000 BTU/lb, 1.0% Sulfur, 13,5% ash, and 10% moisture. The period of prices used in the evaluation is from 1997 through September 2005. Coal prices prior to 1997 were quoted on an annual basis. This level of price quote frequency was useless for the purposes of descriptive statistic development. The figure below shows the historical coal prices used.

Figure 48 - Historical Coal Prices

The historical natural gas, oil, and coal prices were quoted daily in the intervals shown above, while the nuclear prices were quoted monthly. The sparsely quoted nuclear prices gave rise to difficulty in developing the modeling necessary to generate the volatility and mean reversion factors. The number of data points in the nuclear price data set was insufficient for traditional regression development techniques used for the other commodities (described below). The approach taken for the nuclear variance multipliers was to develop a log-normal distribution using the standard deviation of the dataset and then use inter-period correlation to emulate a random walk with mean reversion stochastic process. The inter-period correlation utilized was 50%. By using a correlation that was less than 100%, counter-directional draws (emulating mean reversion) are allowed. The following figure shows the results of 1,000 draws using this technique.

Figure 49 - Nuclear Fuel Price Multiplier Draws



Since the nuclear fuel used a separate development technique, it is impossible to correlate it to the other commodities for the purposes of generating multiplier draws. When analyzing the monthly average historical price data for coal, oil, and gas against nuclear prices, the correlations; 63%, 44%, 55% respectively, are not that strong. Furthermore, the impact of volatility multipliers on nuclear fuel prices is relatively small given that the underlying fuel price is approximately $0.50 /MMBtu. For these reasons, NCI believes that this simple approach does not introduce material error into the analysis.

The approach taken for developing descriptive parameters for the coal, oil, and natural gas commodity prices was far more sophisticated than for nuclear fuel. In the case of these commodities; with underlying prices of natural gas averaging $5.5/MMBtu, oil averaging $10/MMBtu, and coal averaging $2.0/MMBtu over the evaluation period, it is warranted.

Several econometric models were considered for this purpose. First, multivariate GARCH (generalized autoregressive conditional heteroskedasticity)[19] models were considered. These models jointly estimate conditional mean and conditional volatility of a set of time series allowing for cross series effects on the mean and volatility. Such complex models involve the estimation of in excess of 100 parameters, even in the simplest parameterization. Given the limited time series available for the commodity prices (less than 450 observations), this approach was not feasible.

[19] The following articles provide examples and different parameterizations of the multivariate GARCH model: Bollerslev, Engle and Wooldrige (1998), Deb, Trivedi, and Varangis (1996), Engle and Kroner (1995), Haigh and Holt (2002), and Worthington, Kay-Spratley, and Higgs (2005).

The next model considered was the DCC-GARCH model (dynamic conditional correlation GARCH).[20] These models amount to estimating univariate GARCH models for each time series and then estimating a GARCH model on the cross series covariances. I found that these models were unstable in some of the covariances estimated and were therefore not reliable.

The method ultimately used is a variant of the DCC-GARCH model. It proceeds in two steps. In the first step, a set of univariate GARCH models is estimated. In the second step, seasonality of volatility is accounted for by computing the average correlation of residuals across the time series by month of year.

The univariate GARCH models were estimated on the natural logarithm of weekly average price. A mean reverting functional form was adopted where the long run mean was estimated over the longest possible period given the data. Each commodity price was regressed on up to 15 lags of all commodity prices. AR terms with 1 to 5 lags and GARCH terms with 1 to 5 lags were estimated for the volatility equation. Only models that implied stationary time series were considered admissible. The remaining candidate models were ranked according to maximization of log likelihood, Aikaike information criterion (AIC), and Schwarz information criterion (SIC). The final specification was chosen that had highest AIC or SIC and had statistically significant coefficients for the highest lag of prices included in the model. For all commodities the best fitting model was the simplest one: a GARCH (1,1) model with 1 lag of all prices. After estimating the univariate models, the average correlation of standardized residuals across commodities was estimated as well. This month-varying correlation matrix was saved for the simulation stage. The estimating equations are shown below.

[20] See Engle (2002) and Engle and Sheppard (2001) for an overview of these models.

Figure 50 – Estimation Equations

$$c_t = \mu_c\left(1-\beta_c^c\right)+\beta_c^c c_{t-1}+\beta_g^c g_{t-1}+\beta_o^c o_{t-1}+\beta_r^c r_{t-1}+u_t^c$$
$$h_t^c = \alpha_o^c+\alpha_1^c h_{t-1}^c+\delta^c\left(u_{t-1}^c\right)^2$$

$$g_t = \mu_g\left(1-\beta_g^g\right)+\beta_c^g c_{t-1}+\beta_g^g g_{t-1}+\beta_o^g o_{t-1}+\beta_r^g r_{t-1}+u_t^g$$
$$h_t^g = \alpha_o^g+\alpha_1^g h_{t-1}^g+\delta^g\left(u_{t-1}^g\right)^2$$

$$o_t = \mu_o\left(1-\beta_o^o\right)+\beta_c^o c_{t-1}+\beta_g^o g_{t-1}+\beta_o^o o_{t-1}+\beta_r^o r_{t-1}+u_t^o$$
$$h_t^o = \alpha_o^o+\alpha_1^c h_{t-1}^o+\delta^o\left(u_{t-1}^o\right)^2$$

$$r_t = \mu_r\left(1-\beta_r^r\right)+\beta_c^r c_{t-1}+\beta_g^r g_{t-1}+\beta_o^r o_{t-1}+\beta_r^r r_{t-1}+u_t^r$$
$$h_t^r = \alpha_o^r+\alpha_1^r h_{t-1}^r+\delta^c\left(u_{t-1}^r\right)^2$$

where c_t is natural log Appalachian coal price,

g_t is natural log Henry Hub natural gas price,

o_t is natural log heating oil #2 price,

r_t is natural log of 10 U.S. T-bond rate,

μ_i (i=c, g, o, r) is the long run mean for each commodity,

β are the regression parameters to estimate for the conditional mean,

h_t^i (i=c, g, o, r) is the conditional volatility of the series,

α_1^i (i=c, g, o, r) is the ARCH parameter for the series, and

δ^g (i=c, g, o, r) is the GARCH parameter for the series.

The next step was to develop a set of simulations of the price series from the end of estimation sample (July 1, 2005) to the end of December 2035. For each simulation, the following steps were employed.

1. A *simulated coefficient vector* was drawn for all of the model parameters. The model parameters for an estimated model have a multivariate normal distribution with mean equal to the estimated coefficient vector and variance equal the estimated covariance matrix of coefficients. The coefficient vector was drawn until stationarity in mean and variance was satisfied.
2. *Simulated correlated standardized residuals* are created. A 4 by 1 vector of random residuals for the week is drawn according to the multivariate normal distribution with mean zero and covariance matrix equal to the Cholesky decomposition of the appropriate month's correlation matrix.
3. The *conditional variance* is updated. Using the GARCH equation, past residuals, and simulated coefficient vector, an updated conditional variance estimate is made following the formulas above.
4. *Simulated regression residuals* are created. A random draw of the price series residuals is made that is normal with mean zero and variance equal to the updated conditional variance.
5. The *conditional mean* is updated. Using the simulated regression coefficient vector, past history of prices, and simulated regression residual, the conditional mean is updated following the formulas above.

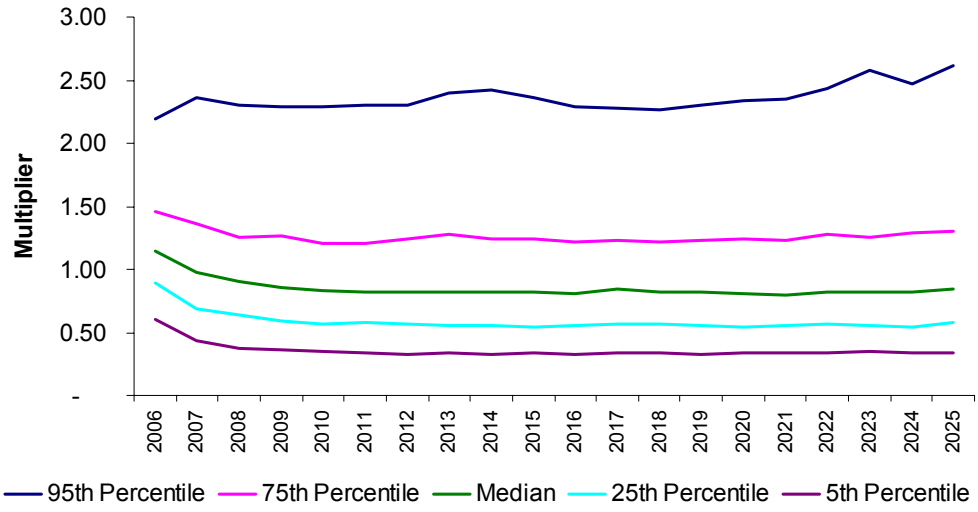
This process was repeated to create 2,000 simulated price paths.

The price paths were aggregated to the month level for further analysis. We eliminated any price simulation as unrealistic if

- the simulated price was more than 5 times baseline price for 36 or more months for any of the commodities, or
- the month to month change in price was more than 400% for any commodity.

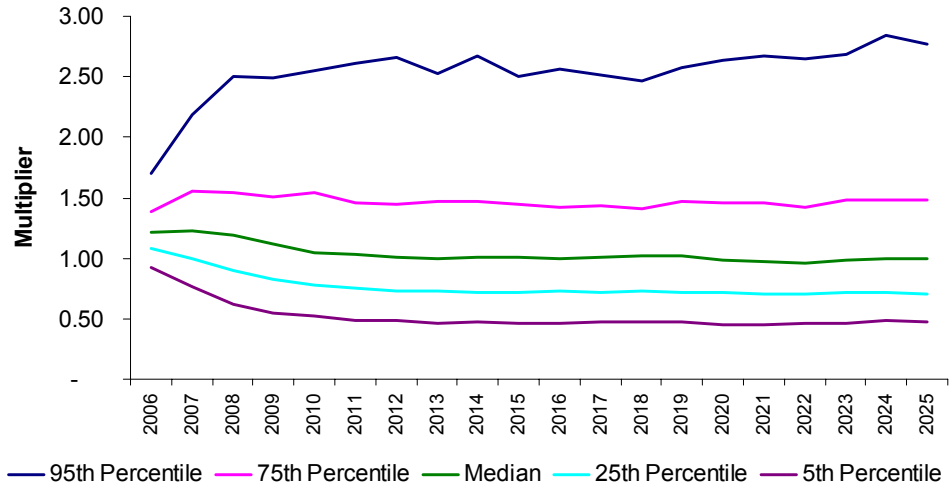
The following figures show the results of the GARCH modeling and time series simulations for natural gas, coal, and oil respectively.

Figure 51 - Natural Gas Volatility Multipliers



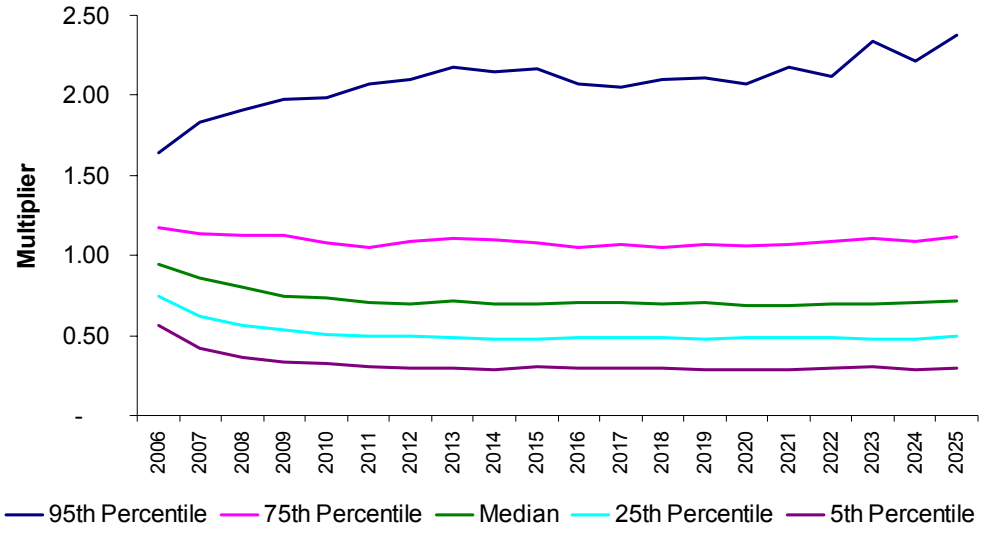
Source: NCI Analysis

Figure 52 - Coal Volatility Multipliers



Source: NCI Analysis

Figure 53 - Volatility Multipliers



Source: NCI Analysis

7 PORTFOLIO SCREENING MODEL OUTPUT

The PSM produces and stores summary data from both the deterministic and stochastic analysis within the model. All output is converted to Canadian dollars at an assumed exchange rate, which in the OPA's PSM was assumed to be 1.20CDN to 1 US dollar. The deterministic analysis produces the following output:

- A revenue requirement statement as described earlier in this document for each year of the 20 year forecast period
- Total energy produced during the year
- A forecast annual average marginal energy cost (corresponding to an annual average market price)
- The total carbon produced during each year of the forecast period
- An environmental intensity analysis of the portfolio
- Annual capacity factors of the existing and forecast unit additions

The output from the stochastic analysis is also stored within the model, but in a more raw from due to the quantity of data produced. To limit the overall memory size of the model and to facilitate more rapid Monte Carlo analysis, the summarizing of the stochastic output is performed in an external Excel reporting model. This reporting model takes the raw stochastic data produced by the PSM and summarizes the results in graphic form as illustrated below:

Figure 54 - Illustrative Distribution of Revenue Requirement for a Sample Portfolio

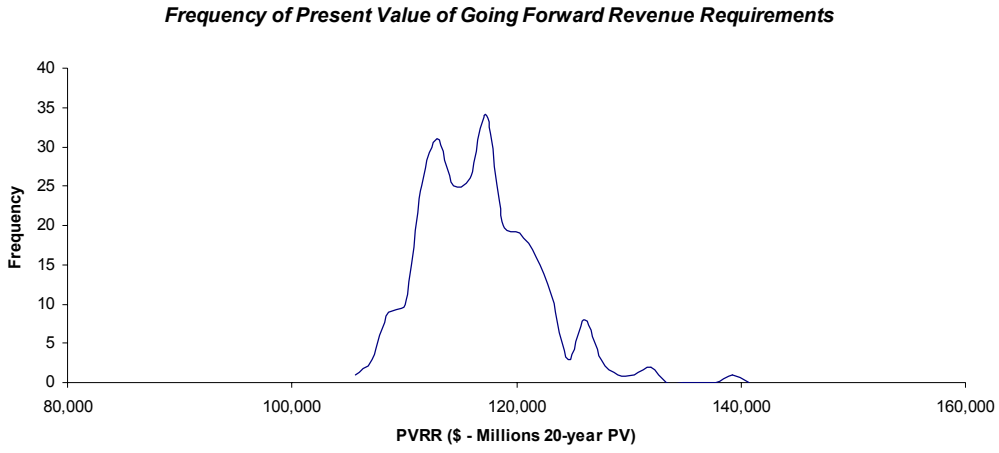


Figure 55 - Illustrative Stochastic Results for Annual Energy Cost

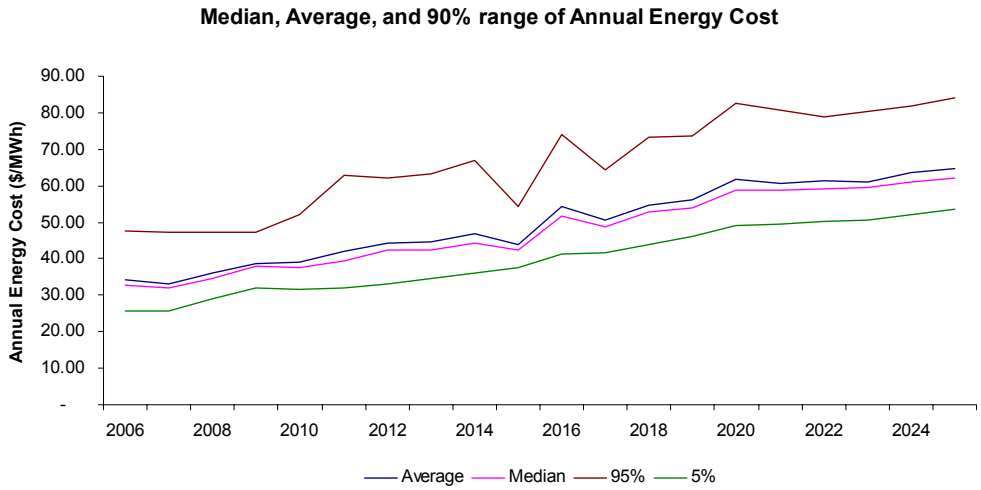


Figure 56 - Illustrative Distribution of Marginal Cost

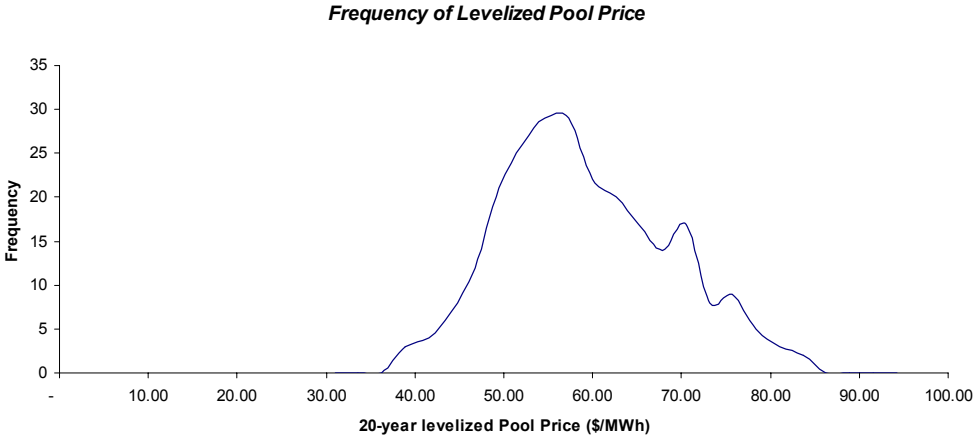
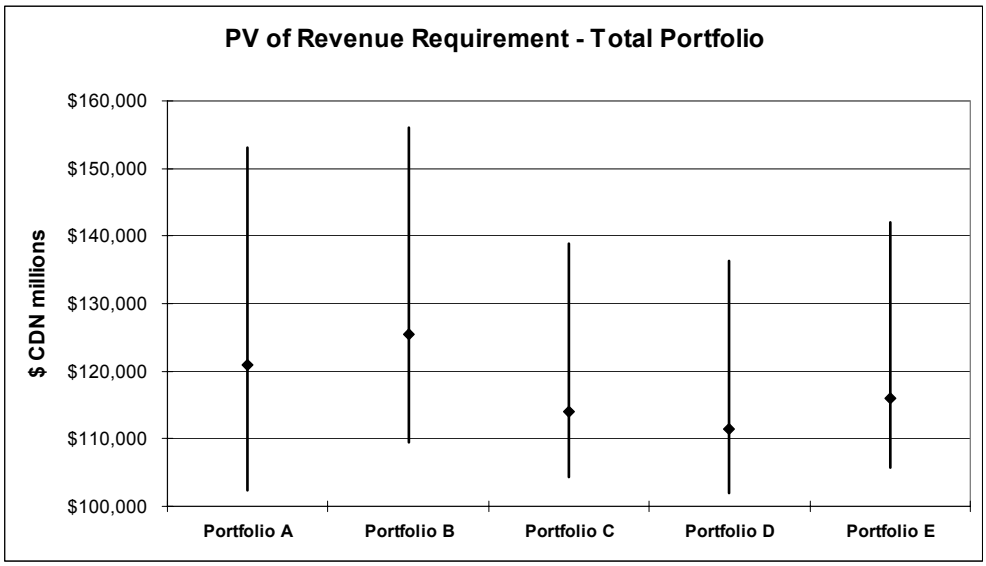


Figure 57 - Comparison Across Portfolios of Cost and Risk



APPENDIX A – ELASTICITY REVIEW DETAILS

This appendix presents the detailed results from our review of the literature on elasticities of substitution for residential customers, commercial customers and for customers with enabling technologies, such as smart thermostats.

7.1 RESIDENTIAL ELASTICITY

Households exhibit a wide range of responses to time of use pricing. A study of focus groups found that approximately half of all households make very little change in electricity consumption in response to price changes while the other half respond actively by taking aggressive load reduction action when prices go up.[21] This same study also looked at how price elasticities vary as a function of income and found that consumers with lower income levels are more responsive to price increases.

Much of the literature on time of use pricing in residential markets stems from a series of demonstration projects in the United States in the 1970's. Some more recent data has become available as results from California's 2003 SPP are released.[22] Two common elements of these studies are that they are generally voluntary, and they tend to be short in duration. As a result, they may overstate the enthusiasm of the broader market to respond to price signals and may also fail to capture the effects of demand response exhaustion.

A position paper prepared by the Australia Essential Services Commission cites an EPRI study that investigated the feasibility of estimating a model that pooled data from high quality experiments.[23] The EPRI researchers found that results have been remarkably consistent across experiments once adjustments were made for a variety of local conditions. The EPRI study estimated that elasticity of substitution was 0.14. These results are similar to the analysis conducted in a 1983 report by Caves, Christensen and Herriges, which indicated an average residential elasticity of 0.13 across 14 U.S. jurisdictions in California, Carolina, Connecticut and Wisconsin.[24]

---

21 Reiss, Peter C. and White, Matthew W., "Household Electricity Demand, Revisited" (December 2001). NBER Working Paper No. W8687. http://ssrn.com/abstract=294736

22 Charles River & Associates Presentation; "California's Statewide Pricing Pilot," January 2005

23 Essential Services Commission, "Installing Interval Meters for Electricity Customers – Costs and Benefits: Position Paper," November, 2002

24 D. W. Caves, L. R. Christensen, and J. A. Herriges, "Time-of-Use Pricing for Residential Electricity Customers: Results from the Wisconsin Experiment," Public Utilities Fortnightly, March 17, 1983

To determine an appropriate substitution elasticity estimate for Ontario, it is critical to consider the most recent results available as well as the difference in reactions to voluntary and mandatory programs. The most recent elasticity research available is from the California SPP. The results of this research indicate an average substitution elasticity of -0.09. Research from San Diego Gas & Electric and the Australia Essential Services Commission indicate that mandatory programs achieve lower elasticities of substitution than voluntary programs do. When these considerations are balanced against the earlier research referred to above, we find that a residential elasticity of substitution value of0.11 is justified.

While it appears that we have assumed an elasticity at the higher end of the range for residential customers, a closer look at the data provides additional insight into our approach. The markets for the low end of the residential customer range of elasticities are primarily moderate climate, coastal zones. In these areas, customers are less likely to respond to price signals because temperatures, and electricity consumption, are less likely to vary throughout the day. When coastal zones are removed from the range, we are left with inland and northern zones (zones with climate characteristics that are more similar to Ontario's) and a range from 0.07 to 0.14. Based on this, our estimate of 0.11 is in the middle of the range. While actual demand response results could be higher or lower than this estimate, we find that focusing on relevant climate zones and adopting a mid-range estimate from these zones is both reasonable and conservative.

Table 21: Residential Elasticities of Substitution

Utility	Customer Type	Participation: Mandatory or Voluntary	Rate Type	Substitution Elasticity
Caves and Christensen Research	Residential	Not Known	TOU	0.13*
Pacific Gas &Electric	Residential – Desert/Mountain	Default rate**	CPP-F	0.14
	Residential – Valley	Default rate	CPP-F	0.13
	Residential – Coastal	Default rate	CPP-F	0.06
	Residential – Inland Hill	Default rate	CPP-F	0.11
San Diego Gas & Electric	Coastal	Mandatory	CPP-F	0.05
	Inland	Mandatory	CPP-F	0.08
Essential Services Commission - Australia	Residential	Mandatory	TOU	0.10
Charles River Associates – SPP research	California - Coastal	Voluntary	CPP-F	0.04
	California - Inland	Voluntary	CPP-F	0.07
	California - Inland Hot	Voluntary	CPP-F	0.12
	California – Desert Hottest	Voluntary	CPP-F	0.13
	Average Elasticity			**0.10**

* This value represents an average of results from 14 U.S. jurisdictions.
** PG&E finds that a default rate with the option for customers to opt-out to other rate structures is the model that will produce the greatest DR benefits.

7.2 COMMERCIAL/INDUSTRIAL ELASTICITY

The research indicates that small businesses and commercial enterprises are less price responsive than residential customers. Commercial customers report that peak usage is harder to curtail when critical business activity and electric use coincide with high price times. Also, businesses with high electricity intensity are less responsive than other customers. These findings seem to indicate that some businesses have less capacity to shift load simply due to the nature of their operations.

In a study of the effect of time sensitive pricing on commercial customers in New York, more than 85% of enterprises reported having made technology investments for load management and energy efficiency prior to the introduction of time sensitive pricing.[25] Of these, energy efficiency measures (including energy efficient lighting, HVAC or motors in these upgrades) were more common than load monitoring or control measures. After the introduction of time sensitive pricing, almost half of the respondents reported making additional investments in technologies aimed at demand response rather than energy efficiency.

In the same study, customers reported having made DR investments to better understand load profile rather than to be price responsive. In other words, energy information was used to reduce overall consumption as well as to reduce usage during peak periods. Neenan et al found that the most common strategies employed by companies are low tech (i.e. reducing usage or shutting off equipment).[26] Interviews suggest that this may result from a lack of awareness surrounding the potential applications and demand reduction potential of enabling technologies. This is consistent with the findings elsewhere that many customers can only curtail load (as opposed to shifting it). A key implication of this research is that demand response includes elements of energy conservation as well as load shifting.

Studies conducted by Pacific Gas & Electric, Australia's Essential Services Commission and at Ernest Orlando Berkely National Laboratory indicate an average elasticity of substitution for commercial customers of 0.08. This is considered slightly high as a result of including the Ernest Orlando Berkley National Laboratory's Niagara Mohawk research which we note is skewed by results from large institutions which would not be covered by our smart meter deployment. In

25 Neenan, Pratt, Cappers and Boisvert, "Does Real-Time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff, " Ernest Orlando Lawrence Berkley National Laboroatory, 2004.

26 Ibid.

consideration of this fact, we have adjusted the commercial elasticities of substitution estimate downward to -0.06.

Table 22: Commercial Elasticities of Substitution

Utility	Customer Type	Participation: Mandatory or Voluntary	Rate Type	Substitution Elasticity
Pacific Gas&Electric	Small Commercial & Industrial	Voluntary	CPP	0.07
Niagara Mohawk	Large Commercial/ Institutional (>2MW)	Mandatory	RTP	0.14*
Essential Services Commission-Australia	Commercial	Mandatory	TOU	0.03
	Average Elasticity			**0.08**

* Figure represents a load weighted average of elasticities: government/educational (0.30); Industrial (0.11) and commercial (0.00). Government/education includes local, state and federal government facilities, universities, schools and other like organizations that share an institutional design making structure. Commercial facilities include retail space, office buildings, hospitals, health care facilities and large multi family housing complexes.

7.3 IMPACT OF TECHNOLOGY

The introduction of load control and other enabling technologies is expected to enhance demand response rates and to produce significant system wide benefits. Unfortunately, there are few examples of wide spread adoption of these technologies in electricity markets with time sensitive pricing. Of the relevant examples, the results are impressive but they also include some bias because the subjects tend to be volunteers and may not be representative of the population as a whole.

To arrive at our estimate for technology enabled demand response, we looked at the peak load reduction differences between rates with and without technology in the California SPP.[27] Rates with technology achieved reductions approximately 2.1 times greater than those without technology. To arrive at our technology-enabled elasticity estimates, we have similarly doubled our residential and commercial elasticity estimates to arrive at technology enabled elasticity values of 0.22 and 0.12 respectively.

However, any benefits that these technologies provide aren't likely to be fully realized in the short-to-medium term. We expect any benefits would not be realized sooner than 15 years from the beginning of the smart meter implementation. In the interest of remaining conservative, have not included them in our base analysis, although the high-elasticity scenario could be considered as partially reflecting a technology-enabled elasticity.

[27] Charles River & Associates; "Statewide Pricing Pilot Summer 2003 Impact Analysis," August 2004

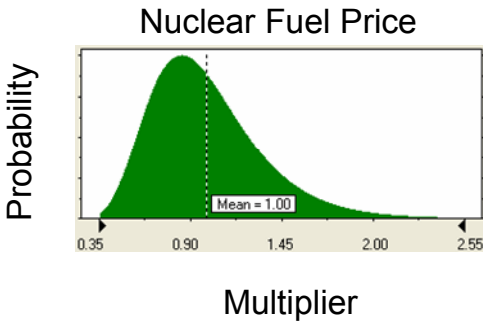
Table 23: Elasticities of Substitution for Technology-Enabled Customers

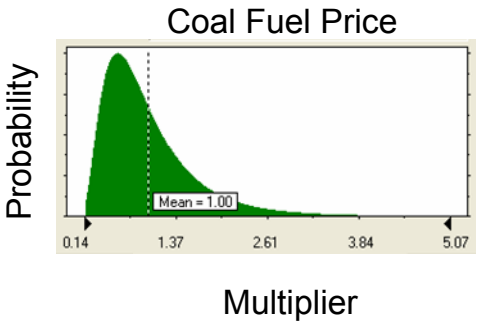
Utility	Customer Type	Participation: Mandatory or Voluntary	Rate Type	Substitution Elasticity
Pacific Gas & Electric	Residential – Zone R*	Voluntary	CPP-F	0.39
	Residential – Zone S*	Voluntary	CPP-F	0.37
	Residential – Zone T*	Voluntary	CPP-F	0.13
	Residential – Zone X*	Voluntary	CPP-F	0.26
	Small Commercial & Industrial	Voluntary	CPP	0.12
Essential Services Commission-Australia	Residential	Mandatory	TOU	0.15
	Commercial	Mandatory	TOU	0.04
	Average Elasticity			**0.21**

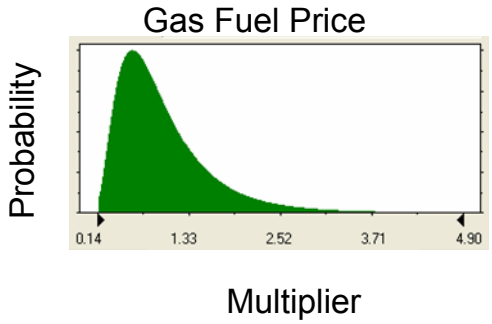
* PG&E considers these customers to be the best source of estimates for technology enabled households but points out that these households are not considered to be representative of the population as a whole because they had previously volunteered in a smart thermostat pilot

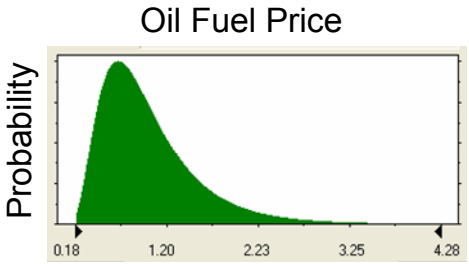
APPENDIX B – RISK VARIABLE DISTRIBUTIONS

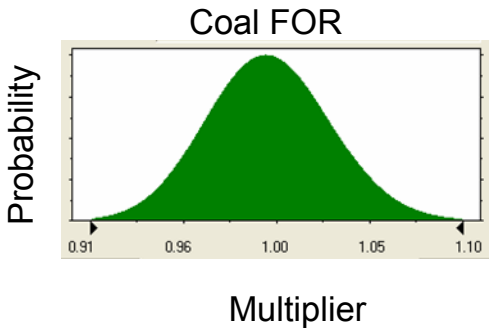
A distribution of possible outcomes for each variable was developed as outlined earlier in the document, then used to modify the deterministic forecast value in the model. The distributions assumed for each of the variables used in the Monte Carlo analysis were as follows where the number 1.0 represents the mean value for the variable:

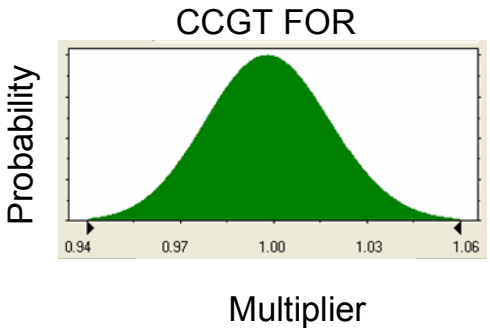


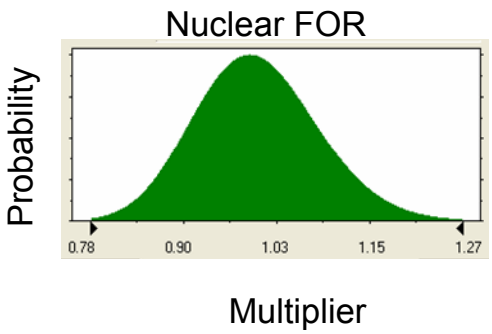


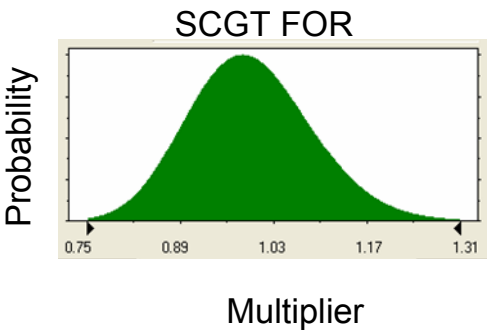


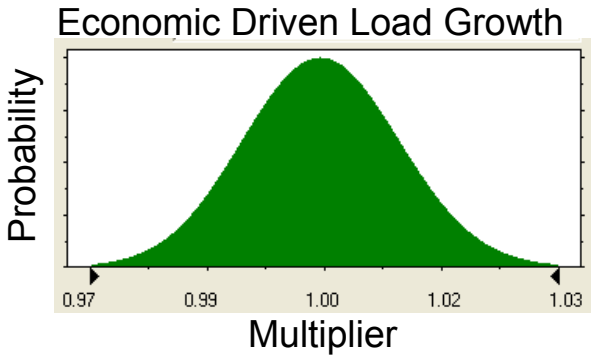


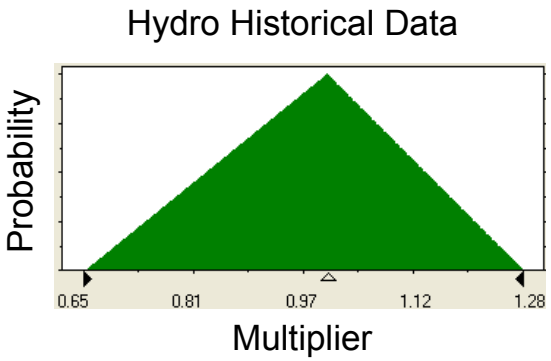









Economic Driven Load Growth
Probability
0.97
0.99
1.00
1.02
1.03
Multiplier


Hydro Historical Data
Probability
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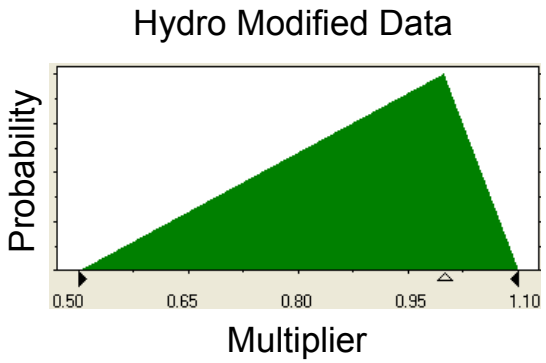
0.81
0.97
1.12
1.28
Multiplier


Hydro Modified Data
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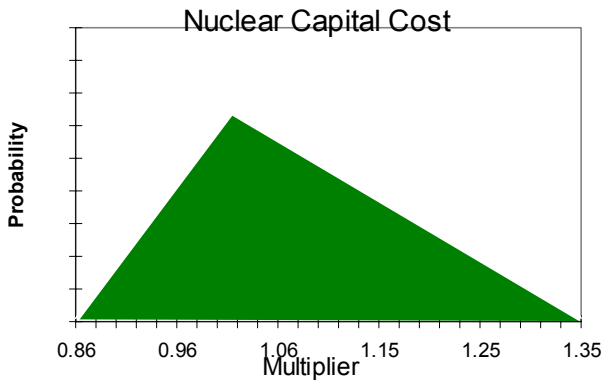
0.65
0.80
0.95
1.10
Multiplier


Nuclear Capital Cost
Probability
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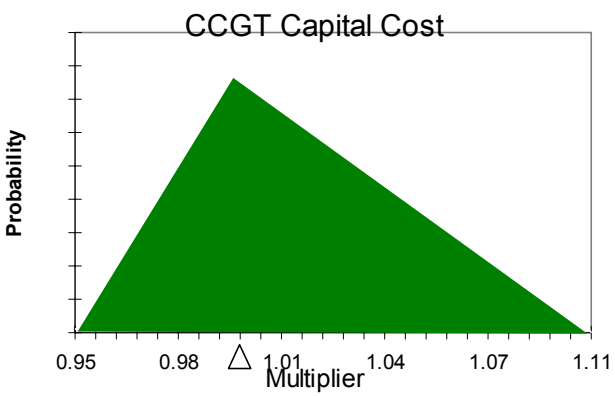
0.96
1.06
1.15
1.25
1.35
Multiplier


CCGT Capital Cost
Probability
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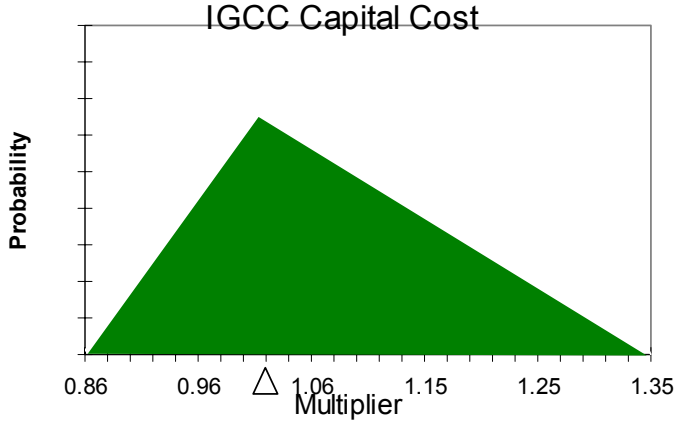
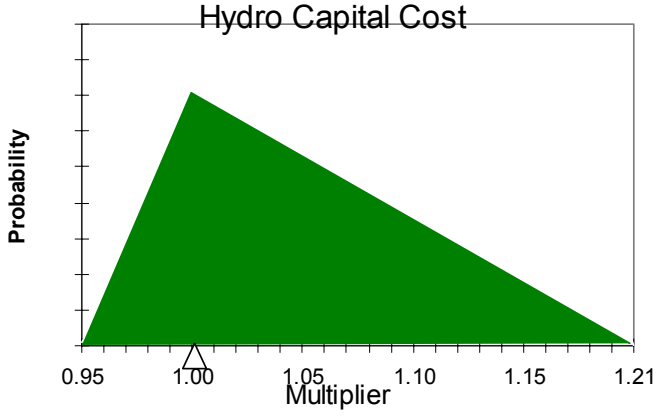
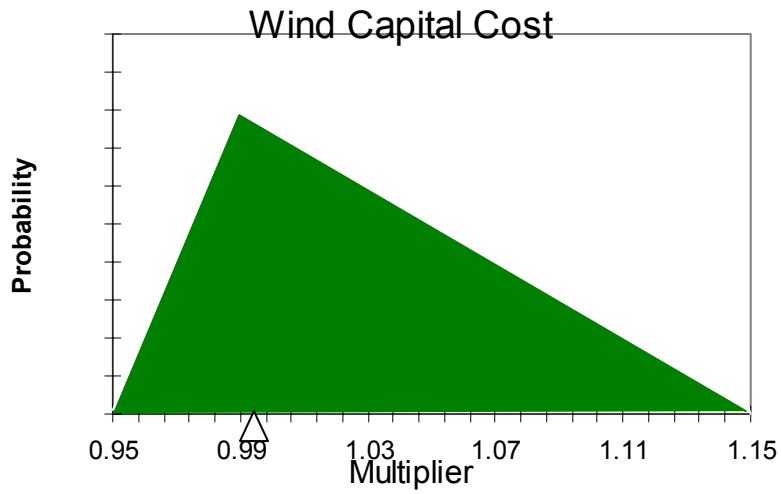
0.98
1.01
1.04
1.07
1.11
Multiplier


IGCC Capital Cost
Probability
0.86
0.96
1.06
1.15
1.25
1.35
Multiplier


Hydro Capital Cost
Probability
0.95
1.00
1.05
1.10
1.15
1.21
Multiplier


Wind Capital Cost
Probability
0.95
0.99
1.03
1.07
1.11
1.15
Multiplier

ICF CONSULTING

Ontario Power Authority

Assessment of Energy Efficiency Potential: 2006–2025

Final Report

August 25, 2005

05-061

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Ontario Power Authority

Assessment of Energy Efficiency Potential: 2006–2025

Final Report

August 25, 2005

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1. Executive Summary

- ICF Consulting is pleased to provide the Ontario Power Authority (OPA) with this assessment of the Conservation and Demand Management (CDM) options available for inclusion in Ontario's Integrated Power System Plan (IPSP). We have sought to identify the magnitude of the energy efficiency resource in Ontario and define plausible policy scenarios for achieving that energy efficiency potential.
- To accomplish this, we have melded two complementary approaches that provide significant detail on the nature of energy efficiency potential in Ontario and benchmark our findings against those of other energy efficiency programs and potential studies in North America:
  - ***Accounting Model Framework***—We have employed ICF's Energy Efficiency Potential Model (EEPM) to provide a detailed bottom-up view of what sectors, sub-sectors, and end uses provide the greatest opportunity for energy efficiency improvements. The scenarios modeled include the following (See tables below):
    - **Naturally-Occurring/Static Efficiency:** The Base Forecast includes some natural market-driven efficiency improvements. The Static Efficiency case shows what the forecast would be without this Naturally Occurring Conservation.
    - **Base Forecast:** This is a segmented end use forecast developed by ICF and based on the key drivers of the IESO forecast.
    - **Minimally Aggressive:** This scenario mimics program intervention that is largely information-based, with financial incentives for measure installation set to 25% of measure incremental cost.
    - **Moderately Aggressive:** This scenario reflects a program approach with financial incentives set to approximately 50% of measure incremental cost with more intensive marketing and technical assistance efforts.
    - **Very Aggressive:** This scenario assumes incentives equal to 100% of measure incremental costs with intensive recruiting and technical assistance.
    - **Very Aggressive plus Aggressive Standards Scenario:** This scenario builds on the rapid market share growth achieved under the very aggressive scenario by implementing aggressive energy efficiency standards starting in 2008.
  - ***Experience-Based Approach***—To benchmark the results from the EEPM analysis, we have reviewed a wide range of other energy efficiency potential analyses and actual program impacts. This review puts our independent estimate of energy efficiency potential in the context of a broad range of energy efficiency experience. Please note the charts below that compare the EEPM results with experience-based results. Overall, our estimates of energy efficiency potential are consistent with the other energy efficiency potential studies and program impacts reviewed.

Table 1. Load Forecast Under Achievable Potential Scenarios (Electricity Sales, MWh)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	151,728,312	181,413,826	203,183,482	220,388,344	236,201,727
Base Forecast	143,627,011	149,385,497	155,834,699	163,018,356	170,985,694
Minimally Aggressive	143,627,011	146,207,525	151,296,634	157,755,491	165,661,370
Moderately Aggressive	143,627,011	141,183,025	145,848,460	154,141,169	164,127,152
Very Aggressive	143,627,011	137,225,627	143,887,495	153,674,082	163,883,757
Very Aggressive Plus Standards	143,627,011	134,256,320	143,295,747	153,465,480	163,669,738

Table 2. Load Forecast Under Achievable Potential Scenarios (Peak Demand, MW)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	24,271	29,464	33,492	36,702	39,653
Base Forecast	23,268	24,804	26,430	28,170	30,025
Minimally Aggressive	23,268	24,366	25,824	27,389	29,040
Moderately Aggressive	23,268	23,691	24,899	26,490	28,538
Very Aggressive	23,268	23,018	24,385	26,353	28,452
Very Aggressive Plus Standards	23,268	22,369	24,071	26,214	28,311

Figure 1. Ontario Electricity Sales Scenarios Based on Moderately Aggressive Achievable Studies

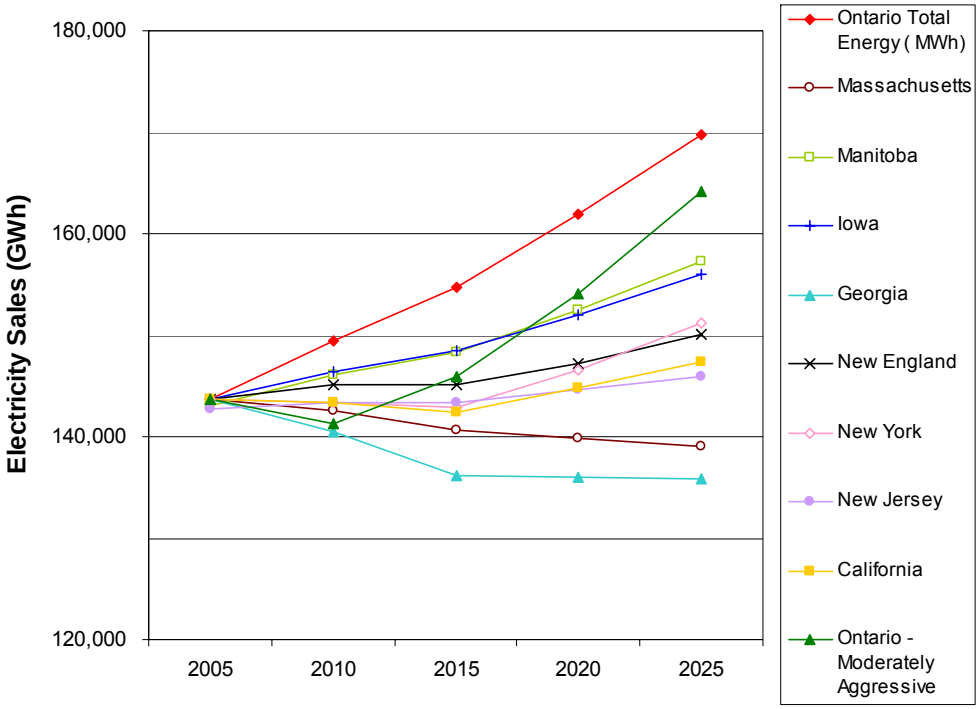
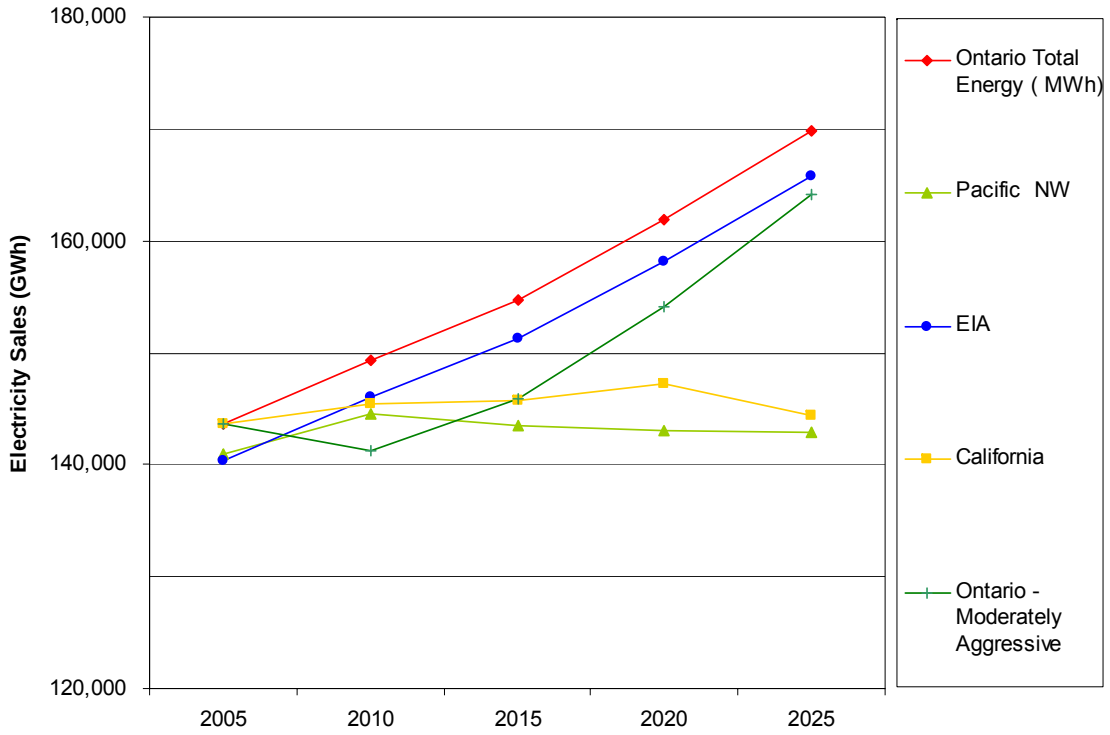


Figure 2. Ontario Electricity Sales Scenarios Based on Program Experience



2. Statement of Study Objectives

- The objective of this assessment is to provide the Ontario Power Authority (OPA) with guidance on the role of energy conservation within its Integrated Power System Plan (IPSP). Specifically, the OPA seeks recommendations pertinent to the development of conservation targets through 2025 within the context of already existing efficiency goals and overall supply mix objectives.
- The OPA seeks further understanding of the energy efficiency portfolio options at its disposal and the risks inherent in each option. Moreover, the OPA requires explicit identification of the action required by government to enact these options.
- ICF intends to meet these objectives through a blending of two approaches. The first approach employs ICF's Energy Efficiency Potential Model (EEPM) to provide estimates of technical, economic, and achievable energy savings potential. To complement these modeling results and place the efficiency potential estimates in the proper context, we have also reviewed other energy efficiency potential estimates and program impacts to summarize the range of both projected and actual industry results.
- In order to use EEPM to more accurately reflect the specific nature of the Ontario market, we have utilized Ontario-specific end use forecast data along with industry data regarding energy efficiency measure costs, applicability, and longevity to model various scenarios of savings potential. The extent to which energy efficiency measures are adopted is dependent on the costs of energy efficiency measures relative to supply side options and the intensity of the projected policy interventions.
- To match the long-term nature of the OPA's planning horizon, we have reviewed the role of advanced energy efficiency technologies in the development of conservation targets. Within the 20-year planning timeframe for this assessment, the technologies available to improve the efficiency of energy-consuming equipment will advance. EEPM mimics this technological evolution in order to properly reflect likely energy efficiency measure market maturation and to provide the OPA with a seamless evaluation of long-term savings potential.
- In addition, this assessment reviews previous industry estimates of savings potential within individual North American jurisdictions. However, many of these studies have only been completed recently, and the plausibility or implausibility of these results may be evident only after the forecast period has passed. Therefore, it is also useful to study the actual historical impact of energy efficiency policies and programs. We have reviewed available industry data on actual program results as an important metric against which to judge the realistic achievability of our projections of energy savings potential. In most cases, the breadth of study of a program's impact will be much less than that for an energy efficiency potential estimate. For example, program impacts usually consist of data limited to a specific end use and sector in a utility's jurisdiction. Nonetheless, these actual program results are useful in gauging the relationship between market penetration and actual savings and program costs.
- We believe that the results from this blended approach will assist the OPA in assessing the role of conservation in its long-term needs for energy supply. The results from our EEPM modeling effort provide a detailed analysis using all available data regarding energy efficient technologies. The results of our review of other potential estimates and program impacts will provide a valuable benchmark for validating these EEPM results.

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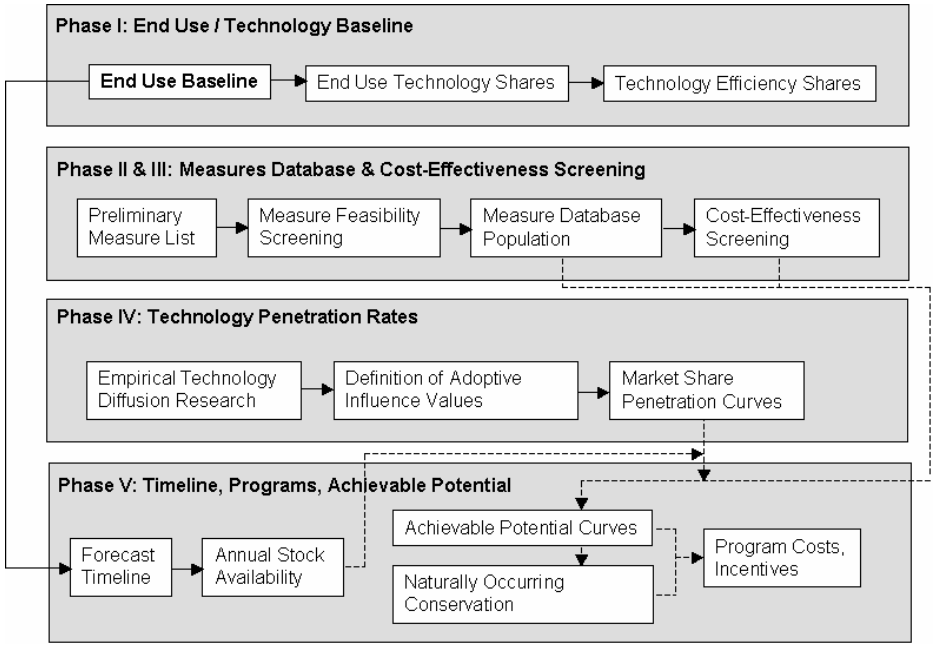
3. Approach

3.1. The Accounting Framework

- ICF Consulting has developed and maintains a sophisticated measure-based Energy Efficiency Potential Model (EEPM) that projects the technical, economic, and achievable potential of a wide range of electric and natural gas efficiency upgrades under several market intervention scenarios. The model develops a detailed representation of demand and assesses the potential for adoption of energy efficiency measures drawn from the model's database of several hundred replace-on-fail and retrofit measures. This database includes both measure performance and cost data. The final results of the modeling process include extensive data on which sectors, sub-sectors, end uses, and measures promise the greatest opportunities for energy efficiency improvement and the costs of acquiring that conservation.
- Our analysis was conducted via the five-stage EEPM modeling process outlined in Figure 3.

Figure 3. Overview of EEPM Approach



3.1.1. Establish the Baseline Forecast

- The first step in the EEPM approach is to establish a baseline energy demand forecast segmented by sector, sub-sector, and end use. ICF developed such a segmented forecast using available historical Ontario energy usage data and IESO forecasts.
- In preparing the baseline forecast for this study, growth rates for Employment and Households used in the IESO's *10 Year Outlook* were used to ensure consistency. The IESO forecast projected these values forward to 2015. In order to extend the baseline forecast to 2025, the growth rates assumed by the IESO for the forecast period were extended to 2020 and 2025. ICF recently prepared a Factor Analysis of the growth in electricity consumption from 1990 to 2003 on behalf of the OPA. This project included a detailed analysis of how electricity use by sector, sub-sector and end use had changed over the period and was used as a basis for projecting future electricity use.
- For the residential sector, the projected growth rate in households is virtually unchanged from the historic period. As a result, residential electricity use was forecast based on extending the rate of change for each end use or appliance over the 1990 to 2005 period forward to 2025.
- For the commercial (service) sector, the historic relationship between growth in employment and growth in floor area was used to project future floor area based on the employment growth forecast obtained from the IESO. Electricity use per square meter within the commercial sector has not changed significantly over the historic period. The electricity intensity per square meter for each sub-sector for 2003 was therefore used to project electricity use to 2025 based on the forecast floor area. Available Ontario data include only four specific end uses for the commercial sector with two additional broad "auxiliary" end uses. To add greater specificity to our results, we have estimated what percentages of these auxiliary categories may fall into more specific end uses.
- In the industrial sector, end use data were not available and sub-sector electricity consumption had varied significantly with respect to economic measures over the historic period. In light of the uncertainties around this variability, electricity use was correlated to the IESO's employment index for the industrial sector as a whole. This relationship was then projected over the forecast period based on 2003 electricity intensity levels. Sub-sector electricity use was then derived from this projection by using 2003 shares. Because no end use data were available, we estimated end use segmentations for each sub-sector using data from the US Energy Information Administration Manufacturer Energy Consumption Survey (MECS).

3.1.2. Measure Database and Cost-Effectiveness Screening

The development of the energy efficiency measures database involved three primary steps.

- A list of approximately 300 energy efficiency measures to be considered for the residential, commercial, and industrial sectors has been compiled for EEPM. These measures represent both replace-on-fail and retrofit options for all major end uses. The measures have been screened for applicability and feasibility for potential utility-sponsored energy efficiency programs.

- Measure data stored for each measure in the EEPM database were cross-checked against existing Ontario and Canadian sources.[1] Data elements associated with each element include incremental capital and installation costs, O&M cost, measure life, and per unit energy and demand savings. Based on our review of other Canadian energy efficiency potential studies and DSM analyses, the measure cost and savings data used in EEPM are consistent with the Ontario climate and market.
- End use savings factors are calculated by first determining the amount of building stock, if any, for a particular building type that can be affected by a particular measure. For instance, a refrigeration measure would be applicable to a grocery or warehouse building, but not to an office building. Then, each measure for a specific end use that had a benefit/cost ratio of 1.0 or greater was aggregated with others in that end use to arrive at an end use level savings factor. For instance, if two cost-effective measures exist for the lighting end use, each with savings potential of 25%, the measures are assumed to be implemented in series so that the overall savings due to application of both measures would be 43.7%. Finally the end use savings factors for all cost effective measures were applied to their respective end use loads to determine savings.
- The cost-effectiveness screening of energy efficiency measures included several steps. The screening process uses what is known as the Technical Cost Test (TCT), similar to the TRC test[2], which compares the incremental measure cost with savings valued at utility avoided costs. The screening also compared the incremental measure cost for each measure with the present value of a future stream of estimated average retail prices (for the Participant Cost Test). Measures with a benefit/cost ratio of 1.0 or greater for the Participant Cost Test were considered eligible for adoption by consumers in developing estimates of naturally occurring energy efficiency. Measures passing the TCT became part of the set of efficiency measures considered in developing estimates of achievable potential.

3.1.3. Determining the Future Penetration Rates of Energy-Efficient Technologies

Naturally Occurring Conservation

- The demand for electricity is rooted in the demand for the end use services, such as lighting or cooling, that electricity provides. Consumers use various types of equipment and respond to various incentives in satisfying their demand for these services.
- Some consumers will choose the high efficiency technology based strictly on the prices they face for the equipment in the market and their perceptions of the costs and benefits of choosing the efficient option. The energy efficiency gain that results from these choices is sometimes called “market-driven.”

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[1] For a study with a longer timeframe, we would also include some refinement of our energy efficiency measure database. However, the database has been recently updated, and we have also completed building simulations for weather-sensitive measures that reflect the climate of the northern US—a reasonable approximation of energy efficiency measure performance in Ontario.

[2] The Technical Cost Test essentially compares the incremental installation cost of a measure with the avoided cost and differs from the Total Resource Cost Test in that at this stage, program administrative costs are not considered.

- Other consumers will tend to choose standard efficiency options unless offered some incentive to buy more efficient equipment. Consumers who make energy efficiency investments by taking advantage of incentive programs already offered contribute to what is referred to as "existing program-driven conservation."
- Taken together, market-driven and existing program-driven conservation make up naturally occurring conservation. In short, naturally occurring conservation includes all energy efficiency gains that would occur in the absence of any additional program or policy interventions.

Achievable Potential

- Even after these two groups of consumers have made decisions to invest in higher efficiency equipment or practices, a large vein of latent energy efficiency remains in the economy represented by consumers who have yet to make equipment replacement choices or who have chosen standard efficiency equipment when earlier choices were made. Achievable potential is represented by the amount of energy efficiency that can be realized by motivating some fraction of these consumers to invest in energy efficiency through ***new*** program or policy interventions.
- Estimating what consumers will do in response to market forces, existing programs and potential new programs requires some method to simulate or forecast the future market penetration of energy efficiency measures. The approach employed here recognizes that consumer choices are based on a wide variety of influences beyond the simple financial aspects of the purchase decision. These influences include consumer awareness of the product, the perceived advantages the product confers beyond energy savings (e.g., convenience, appearance), the perceived performance risk associated with the product, the status it might convey, and so on.[3] This approach is based on the observation that the best predictor of a product's future market share is its past and current market share.[4]
- To implement this analysis, a straightforward mathematical function is employed to simulate the growth of energy efficiency measure market share over time for market-driven, existing program-driven and achievable energy efficiency improvements. This function incorporates three key elements:
  - Market share of the technology or product in an initial year
  - The product's assumed maximum market share; and
  - A parameter representing "adoptive influence," which influences the speed at which a technology gains share in the market.

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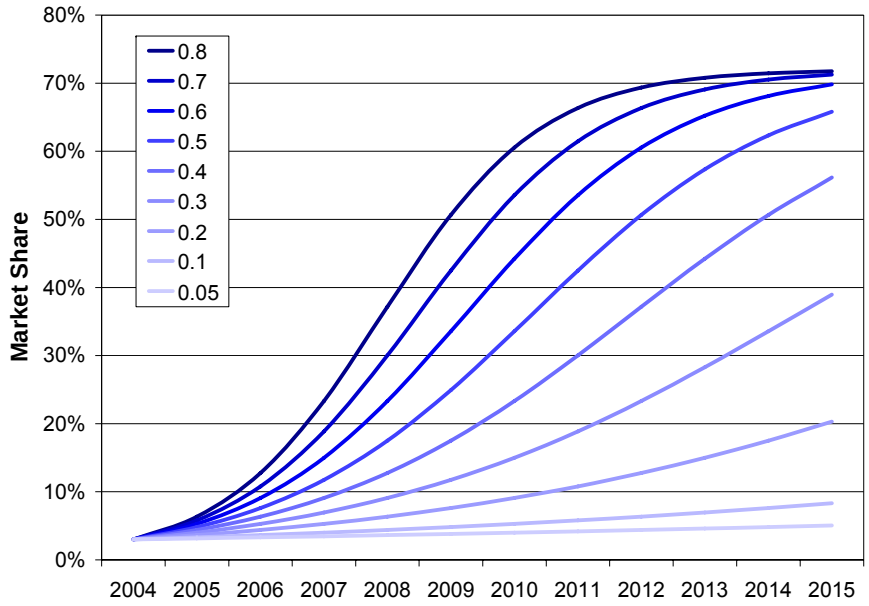
[3] For a complete discussion of the factors that affect consumer decision making and how these factors combine to affect market penetration, see, Everett M. Rogers. *Diffusion of Innovations*. New York: The Free Press. 1995.

[4] See, for example, Shipley, Anna M, et.al. "Market Diffusion Theory and the Penetration of Combined Heat and Power," *ACEEE Summer Study in Buildings*,. Washington, American Council for an Energy Efficient Economy. 2002, Blackman, A Wade. "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change* 6,41-63 (1974), Packey, Daniel J. *Market Penetration of New Energy Technologies*, National Renewable Energy Laboratory, NREL/TP-462-4860. 1993, and DeCanio, Stephen J., and Laitner, John A. "Modeling Technological Change in Energy Demand Forecasting," *Technological Forecasting and Social Change* 55, 249-263 (1997).

- The adoptive influence parameter is estimated from available market share data. The magnitude of the parameter, which can vary between 0.0 and 1.0, determines the shape or compression of the S-shaped adoption curve, which in turn controls how fast a measure/technology/product diffuses through the market (See Figure 4).
- Review of available market share data associated with energy efficiency programs shows that the adoptive influence can be significantly higher for measures affected by these programs than is the case for measures that are not being directly influenced by program intervention.
- The marginal market share projected by this adoptive influence approach represents the annual fraction of replacement and new load that "chooses" energy efficiency as opposed to standard efficiency equipment and practices. The total saturation of energy efficiency measures grows through time as a direct function of the marginal share. Within the model, the adoptive influence parameter increases the marginal market share over time. The higher this value, the greater the annual increase in market share and the faster the increase in total saturation.

Figure 4. Projected Market Adoption Under a Range of Adoptive Influence Values



- Given the nature of the market diffusion process, market share growth tends to be most rapid relatively early in the market life of the technology if it offers compelling market advantages and/or if it is heavily subsidized.
- Based on our research of historical energy efficiency program influence on market shares, we have calibrated EEPM's market adoption curves to several scenarios:
  - **Naturally Occurring—**This scenario reflects efficiency gains from turnover of older equipment to current standard equipment and the adoption of high-efficiency equipment due to natural market forces and existing energy efficiency programs.
  - **Minimally Aggressive—**This scenario is consistent with a portfolio of energy efficiency programs offering modest financial incentives (~25% of incremental costs) with limited marketing and outreach.
  - **Moderately Aggressive—**This scenario is consistent with a portfolio of energy efficiency programs offering more generous financial incentives (~50% of incremental costs) with more extensive marketing and outreach.
  - **Very Aggressive—**This scenario is consistent with a portfolio of energy efficiency programs offering highly aggressive incentives (~100% of incremental costs) with extensive marketing and outreach efforts. This type of scenario is considered to reflect the maximum possible achievable potential. Efficiency potential in the Very Aggressive case still does not capture all economic potential. Even with financial incentives covering the full cost of efficient equipment, some customers will not be influenced to invest in energy efficiency.

3.1.4. Determining the Technical, Economic, and Achievable Potential for Energy Efficiency

- **Technical potential** quantifies the savings that could be realized if energy efficiency measures were applied in all technically feasible instances, regardless of cost. It is typically defined as the amount of energy efficiency improvement that would result if all existing energy-using equipment was replaced with the most efficient alternative, irrespective of cost. As is often the case, we estimate technical potential assuming that this change-out occurs immediately. Technical potential is therefore useful as a broad gauge of the economy's inefficiency in the territory of interest.
- **Economic potential** is the subset of technical potential that is cost-effective from a TCT perspective. As for technical potential, economic potential assumes that all relevant energy efficiency improvements occur instantaneously.
- **Achievable potential** typically is defined as the amount of cost-effective energy efficiency improvement expected to be captured as the result of specific policy or program actions, over-and-above the efficiency improvements attributable to normal consumer and market behavior and existing conservation policies and programs. This class of efficiency potential is distinguished from technical and economic potential in three important ways.
  - First, as the term implies, achievable potential is defined in terms of what realistically can be captured by explicit actions.
  - Second, and following from the first point, achievable potential is time-dependent. Achievable potential only can be realized by convincing consumers to replace existing equipment and practices with new, more efficient equipment and practices. It is often the case that consumers are

most easily convinced to adopt high efficiency alternatives when they must make equipment replacement decisions anyway. Therefore, what is considered achievable potential grows over time as an increasing amount of the existing equipment stock reaches the end of its useful life.

- Finally, achievable potential intrinsically is a function of consumer behavior. The amount of potential one might expect is based on assumptions about what consumers will do when faced with various policy and program interventions. Because estimates of achievable potential consider this difficult-to-predict consumer behavior, they are inherently more uncertain than estimates of technical or economic potential.

- To model achievable potential, it is necessary to track the turnover of energy consuming equipment.
  - For each year, a certain amount of energy consuming equipment must be replaced and new equipment is added. As existing equipment reaches the end of its useful life and is replaced, new equipment is purchased at either a base or high-efficiency level as determined by the projected market shares for high-efficiency equipment.
  - Replace-on-fail measures are only available for implementation as older equipment is replaced, but retrofit measures may be implemented at any time. Retrofit measures include:
    - Measures that do not replace any existing equipment (e.g., pipe insulation added to non-insulated pipes).
    - Measures that replace existing equipment but are cost-effective even when the full cost of the new high-efficiency equipment is considered. For example, the incremental cost of a high-efficiency 15 SEER residential central air conditioning unit is the difference in cost between a 15 SEER unit and a standard 13 SEER unit. For an equipment replacement such as this, cost-effectiveness for replace-on-fail is calculated based on this incremental cost and the incremental savings achieved by selecting a 15 SEER over a 13 SEER unit. However, if the incremental savings achieved by the 15 SEER unit were enough to overcome the *full* cost of the equipment and installation, the existing unit may be replaced by the 15 SEER at any time.

3.1.5. Treatment of Emerging Technologies

- As the market for a particular energy efficiency technology matures, it may be reasonable to make that technology the new standard. This is particularly relevant for a study with a 20-year horizon such as this one.
- To model the changing technological landscape, we have included emerging or advanced energy efficiency technologies in our analysis for the OPA. Once a technology begins to approach full saturation in the market, EEPM establishes this technology as the new standard efficiency and allows the emerging technology to take over the position as the high-efficiency option. This process, in essence, models the transformation of the market to high-efficiency equipment and the subsequent entrance into the market of the next generation of high-efficiency equipment.
- The technical applicability and economics of these emerging technologies is more speculative than for current commercially available technologies, but it is important to address broad technological change over a 20-year time frame.

3.1.6. Description of the Scenarios and Key Data Sources

Scenarios of Achievable Potential

- In conjunction with the OPA, we have developed several scenarios of achievable potential to describe the impacts of different types of policy interventions:
  - **Naturally-Occurring/Static Efficiency:** Naturally occurring conservation reflects efficiency gains from turnover of older equipment to current standard equipment and the adoption of high-efficiency equipment due to natural market forces and existing energy efficiency programs. The scenario is calibrated to adoptive influence values ($A \approx 0.125$) reflecting the adoption behavior characteristic of an environment in which there is a relatively high level of awareness of energy efficiency and some history of program activity, but no current subsidized energy efficiency activity beyond existing codes and standards. The **Base Forecast** includes this level of naturally occurring conservation, so we have added naturally occurring conservation on top of the Base Forecast in order to represent load growth in a state of Static Efficiency where no efficiency gains are realized.
  - **Base Forecast:** This is the segmented end use forecast developed by ICF and based on the key drivers in the IESO forecast.
  - **Minimally Aggressive:** This scenario attempts to mimic program intervention that is largely information-based, with financial incentives for measure installation set to 25% of measure incremental cost. ($A \approx 0.25$)
  - **Moderately Aggressive:** This scenario reflects a fairly common program approach wherein, financial incentives are set equal to approximately 50% of measure incremental cost. In addition, program implementation costs are assumed to be higher due to more intensive marketing and technical assistance efforts. ($A \approx 0.50$)
  - **Very Aggressive:** Here we assume that incentives are equal to 100% of measure incremental costs and program implementation costs are correspondingly higher reflecting intensive recruiting and technical assistance. ($A \approx 0.75$)
  - **Very Aggressive plus Aggressive Standards Scenario:** In our work for the OPA we have built additional structure into the accounting framework to allow us to simulate the introduction of emerging technologies. This structure can be used to represent imposition of a broad range of generic standards. For example, switching the year at which the advanced technologies begin to enter the market we convert the current high efficient measures to standards. For this scenario, we assume that Ontario implements a series of aggressive standards starting in 2008 to build upon the rapid market share growth achieved under the very aggressive scenario. Once these standards are implemented, the minimum efficiency equipment that can be bought is the high-efficiency category. At the same time, an emerging technology enters the market at a low initial market share and is gradually accelerated into the market.

3.1.7. Key data sources

There are three basic types of data required for the Energy Efficiency Potential Model approach.[5]

- **Load Data—**These data include any available electricity sales or peak demand forecasts as well as segmentations of load by sectors, sub-sector, end use, and technology type. The electricity sales forecast was developed as described above from historical energy consumption trends and the IESO's projected energy demand drivers. This sales forecast was converted to summer peak demand using the IESO's peak demand forecast and a series of load factors specific to the northern United States climate.
- **Utility Cost Data—**Avoided utility costs of electricity are used to determine the resource value of conserved energy and determine cost-effectiveness of energy efficiency measures and program portfolios. Our source for these data was the recent Navigant Consulting study on avoided costs presented to Hydro One Networks.[6]
- **Energy Efficiency Market Data—**We cross-checked EEPM's measure database against recent Canadian energy efficiency potential studies and DSM analyses to determine the reasonableness of our cost and savings assumptions for the Ontario climate and equipment market. We observed no systematic bias in our energy efficiency market data relative to that which was available for Ontario.

3.2. The Experience-Based Approach

- Dozens of estimates of energy efficiency potential have been prepared for jurisdictions in North America over the past decade providing a rich pool of information against which the results of the Accounting approach described above can be compared. This information on potential can be placed in context by also examining the results of actual DSM program implementation. This section briefly summarizes estimates of potential and program impacts gathered from a wide range of sources. Where the data permit, estimates of potential and program impact expressed in relative terms (percentage reduction in energy or peak) are applied to the base energy forecast used in the Accounting Framework to illustrate the absolute magnitude of savings if such reductions were achieved in Ontario.
- In many cases the time horizon for which estimates of DSM potential were prepared in these other studies differs from that used in this assessment. Many studies focus on horizons of ten or fifteen years as opposed to the twenty-year view taken here. In such cases, the estimates of efficiency potential, again expressed in relative terms, were extended from their end-point by simple linear extrapolation subject to a cap defined by the studies' estimates of total economic potential. Similarly, where only a single year estimate of potential was reported (e.g. total achievable potential by the year 2015), relative savings for preceding years was estimated using linear extrapolation. Although the adoption of energy efficiency measures typically follows an S-shaped path, the linear extrapolation used here is sufficient for comparative purposes.

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[5] For a study with a longer timeframe, we would also include some refinement of our energy efficiency measure database. However, the database has been recently updated, and we have also completed building simulations for weather-sensitive measures that reflect the climate of the northern US—a reasonable approximation of energy efficiency measure performance in Ontario.

[6] Navigant Consulting, *Avoided Cost Analysis for the Evaluation of CDM Measures*. June 2005.

3.2.1. Data Sources

Estimates of Efficiency Potential

Table 3. Index of Reviewed Energy Efficiency Potential Studies

Organization Name and Author	Title	Year	Jurisdiction	Sectors Considered
ACEEE Margaret Suozzo, Steven Nadel, Jeff Harris, Tom Eckman	Selecting Targets for New Market Transformation Initiatives in the Northwest	1998	Oregon, Washington	Residential, Commercial & Industrial
ACEEE R. Neal Elliott	Electricity Consumption and the Potential for Electric Energy Savings in the Manufacturing Sector	1994	U.S.	Manufacturing
Optimal Energy John Plunkett Phil Mosenthal Chris Neme	Vermont Department of Public Service Electric and Economic Impacts of Maximum Achievable Statewide Efficiency Savings 2003-2012	2002	Vermont	Residential, Commercial & Industrial
RLW Analytics, Inc.	The Remaining Electric Energy Efficiency Opportunities in Massachusetts Final Report	2001	Mass.	Residential, Commercial & Industrial
Kema-Xenergy, Inc. Fred Coito & Mike Rufo	California Statewide Commercial Sector Energy Efficiency Potential Study	2002	California	Commercial
Kema-Xenergy, Inc. Fred Coito & Mike Rufo	California Statewide Residential Sector Energy Efficiency Potential Study	2003	California	Residential
BC Hydro	BC Hydro Conservation Potential Review 2002 Summary Report	2003	British Columbia	Residential, Commercial & Industrial
Ecotope, Inc. ACEEE, and Tellus Institute Shelly Borrelli, David Baylon	Energy Efficiency and Conservation Measure Resource Assessment for the Residential, Commercial, Industrial and Agricultural Sectors	2003	Oregon	Residential, Commercial & Industrial
GDS Associates and Quantum Consulting Jeff Schlegel, Richard Spellman	Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region - Final Report	2004	Connecticut	Residential, Commercial & Industrial

Organization Name and Author	Title	Year	Jurisdiction	Sectors Considered
Southwest Energy Efficiency Project Howard Geller, Neal Elliott, Toru Kubo, Steve Nabel, Anna Shipley	The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest	2002	Six states in the SW US	Residential, Commercial & Industrial
New York State Energy Research and Development Authority (NYSERDA)	Energy Efficiency and Renewable Energy Resource Development Potential in New York State	2003	New York	Residential, Commercial & Industrial
Oak Ridge National Laboratory (ORNL) Stan W. Hadley	The Potential for Energy Efficiency in the State of Iowa	2001	Iowa	Residential, Commercial & Industrial
Tellus Institute	An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah	2001	Utah	Residential, Commercial, & Industrial
Richard Brown	Estimates of the Achievable Potential for Energy Efficiency Improvements in U.S. Residences	1993	U.S.	Residential
Synapse Energy Economics	Repowering the Midwest: The Clean Energy Development Plan for the Heartland	2001	Illinois, Indiana, Iowa, Michigan, Minnesota, Nebraska, North Dakota, Ohio, South Dakota	Residential, Commercial & Industrial
ACEEE Marshall Goldberg, Martin Kushler, Steven Nadel	Energy Efficiency and Economic Development in Illinois	1998	Illinois	Residential, Commercial & Industrial
KEMA	New Jersey Energy Efficiency and Distributed Generation Market Assessment	2004	New Jersey	Residential, Commercial & Industrial
Optimal Energy	Economically Achievable Energy Efficiency Potential in New England	2004	New England	Total
Demand Side Energy / Marbek	Manitoba Hydro DSM Market Potential Study	2003	Manitoba (Manitoba Hydro Territory)	Residential, Commercial & Industrial
ICF Consulting	Assessment of Energy Efficiency Potential In Georgia	2005	Georgia	Residential, Commercial & Industrial
ICF Consulting	Estimate of Energy Efficiency Potential for Wisconsin Public Service	2004	Wisconsin Public Service Co. territory	Residential, Commercial & Industrial

Estimates of Program Impact

- Discussions with the OPA suggested an interest in being able to apply the results of best practice program results to baseline Ontario load as an indication of the impact that adoption of similar programs might have in Ontario. Unfortunately, although there is a growing literature on best practice and exemplary programs, the information readily available for these programs does not allow straightforward translation into potential impacts in Ontario. Program results tend to be expressed in absolute terms (GWh or MW saved). The time allowed for this project did not allow us to collect base sales and demand data for each of the utilities for which we have program impact information.
- We have nevertheless compiled a partial list of those programs, and should the OPA wish, we can pursue the base sales and demand data that would allow conversion of program results in a form that could be applied to the Ontario case.

Table 4. Reviewed Energy Efficiency Program Data

Organization	Program	Year	Jurisdiction	Sector	Target Population	% Participation	Total Period GWh Savings	Total Period Costs / Budget (mil $)
Efficiency Vermont	Multi-family Residential Low-Income Program	1997–2002	Vermont	Residential	Unknown	Unknown	12.3	8.5
New Jersey Clean Energy Collaborative	Cool Advantage—Residential Air-conditioning	2002	New Jersey	Residential	50,000 (annual)	30%	14.0	17.0
NYSERDA	Keep Cool—Residential Air-conditioning	2002	New York	Residential	Unknown	Unknown	104.0	20.0
Proctor Engineering	Check Me!—Air-conditioning	2002	California	Residential, Commercial	Entire US	Unknown	33.1	4.5
Northeast Residential Energy Star Appliances Initiative	Appliances	2002	New England, New York	Residential	2.2 mil	22% (2002) 2.4% (1998–2002)	0.8	0.2
SMUD	Old Refrigerator Pickup and Recycling	2002	Sacramento, CA	Residential	450,000	2%	13.7	1.2
Southern California Edison	Residential Appliance Recycling Program	2002	Southern California	Residential	3.9 mil	5-10%	44.6	4.8
Texas	Texas Energy Star Homes Program	2000–2002	Houston and Dallas, TX	Residential	78,000	15-20%	41.8	9.6
Austin, Texas	Green Buildings Program	2002	Austin, TX	Residential	1,200	57%	12.3	1.2
Northeast Energy Efficiency Partnership	Northeast Regional Energy Star Lighting Program	2001	Northeast	Residential	5.2 mil	Unknown	167.0	17.0
Northwest Energy Efficiency Alliance	Energy Star Residential Windows Program	1998–2001	Oregon, Washington, Montana, Idaho	Residential	New construction	75%	364.0	1.8
National Grid	Small Business Services	2002	New England	Commercial	77,000	33%	13.6	1.0

Organization	Program	Year	Jurisdiction	Sector	Target Population	% Participation	Total Period GWh Savings	Total Period Costs / Budget (mil $)
Avista Utilities	Rooftop HVAC Maintenance Service	2001	Spokane, WA	Commercial	18,000	11%	13.0	1.8
Portland General Electric	Existing Building Commissioning	2001	Portland, OR	Commercial	Unknown	Unknown	6.5	0.3
US EPA	Energy Star Monitor Power Management Program	2002	US	Commercial	Unknown	Unknown	232.0	0.5
Pacific Gas & Electric	Compressed Air Management Program	2003	San Francisco, CA	Commercial, Industrial	14,000	1%	9.4	0.2
Xcel Energy	Lighting	2001–2003	Minnesota	Commercial, Industrial	Unknown	Unknown	204.2	12.2
SMUD	Cool Roof	2001–2002	Sacramento, CA	Commercial	Unknown	Unknown	0.6	1.0
Pacific Gas & Electric	Upstream Residential Lighting Program	2001–2003	Northern California	Residential, Commercial	4.5 mil	8%	1521.5	34.9
SMUD	Shade Tree Program	2001–2003	Sacramento, CA	Residential	350,000	37%	14.4	4.8
Wisconsin Energy Conservation Commission	Energy Star Products	2001–2002	Wisconsin	Residential	2.3 mil	24%	25.5	18.8
Wisconsin Energy Conservation Commission	Energy Star Homes	2001–2002	Wisconsin	Residential	20,000	4%	0.4	0.3
Wisconsin Energy Conservation Commission	Home Performance	2001–2002	Wisconsin	Residential	1.4 mil	1%	5.1	3.8
Connecticut Light and Power, Western Massachusetts Electricity Company	Small Business Energy Advantage	2001–2003	Connecticut, Massachusetts	Commercial	108,000	35%	58.3	21.0

- Among the programs reviewed, some of the overall findings that have lead to greater penetration and increased savings were:
  - Residential customers benefited from programs with point-of-purchase discounts and reduced administrative requirements. In addition, residential programs often featured prompt rebates, and hands-on customer service contact between customers and the utility or a contractor.
  - Commercial customers benefited from programs with trained sales and implementation staff. Commercial programs were also more likely to have upstream involvement, with manufacturers, through the use of innovative marketing techniques.
  - Other characteristics not limited to a specific sector included advance market research and increased community-based marketing and advertising. Turnkey installation was also important in effective participation and implementation. Successful programs also featured close relationships among utilities, state agencies, and manufacturers. Also, in many of the programs, manufacturers were interested in increasing market share and promotional activity rather than financial incentives.
- As an alternative approach, we have identified several sources of time series program impact data that can be matched to sales and demand data to yield percentage reductions in load resulting from program implementation.
  - The Regional Technical Forum associated with the Northwest Power Planning Council publishes annual energy efficiency program data dating to the 1980s as well as historical load data. The Pacific Northwest, by most accounts, has had the most consistently high levels of energy efficiency investment over the past two decades of any area aside from California. We have used these data to calculate annual percentage reductions in sales and demand due to energy efficiency programs, federal standards and state building codes. These relative reductions are applied to projected Ontario load to suggest the level of impact that could be achieved with similar aggressive and consistent investment.
  - A second source of such data is the US Department of Energy's Energy Information Administration (EIA). From the mid-1980s through 2002, EIA collected annual estimates of energy efficiency program impacts. These estimates when applied to historic sales and demand data for US utilities supports an estimate of relative impact similar to that calculated for the Pacific Northwest.
  - The California Energy Commission (CEC) has been tracking energy efficiency impacts upon total load from the mid-1970s through the present. More than half of the savings have been as a result of utility programs, with the remainder from building standards and appliance standards. We have used these data to calculate annual percentage reductions in sales and demand. Similarly, these relative reductions are applied to projected Ontario load to suggest the level of impact that could be achieved with similar aggressive and consistent investment.

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4. Results

4.1. Accounting Approach

- This section presents the results of the accounting model approach. The results include estimates of instantaneous technical and economic potential as well as annual projections of achievable potential under a variety of program scenarios.

4.1.1. Technical and Economic Potential

- The tables and figures below show 2004 electricity sales and estimated peak demand for each sector along with our estimates of instantaneous technical and economic potential based on that load.

Table 5. Technical and Economic Potential

		MWh			MW	
Forecast	2004 Load	Technical Potential	Economic Potential	2004 Load	Technical Potential	Economic Potential
Residential	46,941,752	12,065,412	10,072,530	6,943	2,884	1,744
Commercial	52,867,545	16,404,593	11,986,647	10,241	3,757	2,077
Industrial	41,863,050	8,438,573	7,357,910	7,363	1,463	1,187
Total	141,672,347	36,908,578	29,417,087	24,546	8,103	5,008

Figure 5. 2004 Load, Technical & Economic Potential by Sector (Electricity Sales)

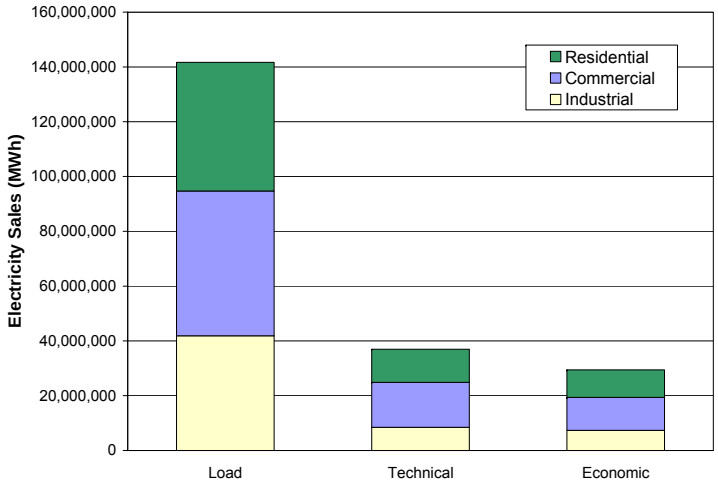
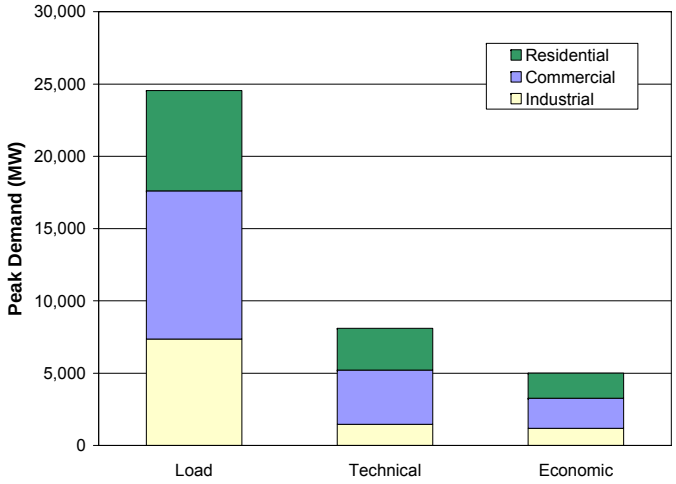


Figure 6. 2004 Load, Technical & Economic Potential by Sector (Peak Demand)



4.1.2. Naturally Occurring and Achievable Scenarios

Overview

- The tables and figures on the following pages summarize our EEPM-based accounting model results for achievable energy efficiency potential from 2005 to 2025. Fully detailed tables and graphs of our results may be found in the appendix.
- The following are the achievable potential scenarios modeled for this study:
  - **Naturally-Occurring/Static Efficiency:** Naturally occurring conservation reflects efficiency gains from turnover of older equipment to current standard equipment and the adoption of high-efficiency equipment due to natural market forces and existing energy efficiency programs. The Static Efficiency case shows what load would be in absence of this naturally occurring energy efficiency.
  - **Base Forecast:** This is the segmented end use forecast developed by ICF and based on the key drivers in the IESO forecast.
  - **Minimally Aggressive:** This scenario attempts to mimic program intervention that is largely information-based, with financial incentives for measure installation set to 25% of measure incremental cost. ($A \approx 0.25$)
  - **Moderately Aggressive:** This scenario reflects a fairly common program approach wherein, financial incentives are set equal to approximately 50% of measure incremental cost. In addition, program implementation costs are assumed to be higher due to more intensive marketing and technical assistance efforts. ($A \approx 0.50$)
  - **Very Aggressive:** Here we assume that incentives are equal to 100% of measure incremental costs and program implementation costs are correspondingly higher reflecting intensive recruiting and technical assistance. ($A \approx 0.75$)
  - **Very Aggressive plus Aggressive Standards Scenario:** For this scenario, we assume that Ontario implements a series of aggressive standards starting in 2008 to build upon the rapid market share growth achieved under the very aggressive scenario. Once these standards are implemented, the minimum efficiency equipment that can be bought is the high-efficiency category. At the same time, an emerging technology enters the market at a low initial market share and is gradually accelerated into the market.
- Estimated achievable energy efficiency potential is divided fairly evenly among the residential, commercial, and industrial sectors.
- Lighting, space heating, and industrial processes make up the majority of electricity sales savings potential. Commercial office equipment and air conditioning also contribute significantly to overall savings.
- Peak demand savings potential is dominated by air conditioning and industrial processes, with lighting also playing an important role.

Table 6. Load Forecast Under Achievable Potential Scenarios (Electricity Sales, MWh)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	151,728,312	181,413,826	203,183,482	220,388,344	236,201,727
Base Forecast	143,627,011	149,385,497	155,834,699	163,018,356	170,985,694
Minimally Aggressive	143,627,011	146,207,525	151,296,634	157,755,491	165,661,370
Moderately Aggressive	143,627,011	141,183,025	145,848,460	154,141,169	164,127,152
Very Aggressive	143,627,011	137,225,627	143,887,495	153,674,082	163,883,757
Very Aggressive Plus Standards	143,627,011	134,256,320	143,295,747	153,465,480	163,669,738

Table 7. Load Forecast Under Achievable Potential Scenarios (Peak Demand, MW)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	24,271	29,464	33,492	36,702	39,653
Base Forecast	23,268	24,804	26,430	28,170	30,025
Minimally Aggressive	23,268	24,366	25,824	27,389	29,040
Moderately Aggressive	23,268	23,691	24,899	26,490	28,538
Very Aggressive	23,268	23,018	24,385	26,353	28,452
Very Aggressive Plus Standards	23,268	22,369	24,071	26,214	28,311

Figure 7. Achievable Potential Scenarios – 2005-2025 (Electricity Sales)

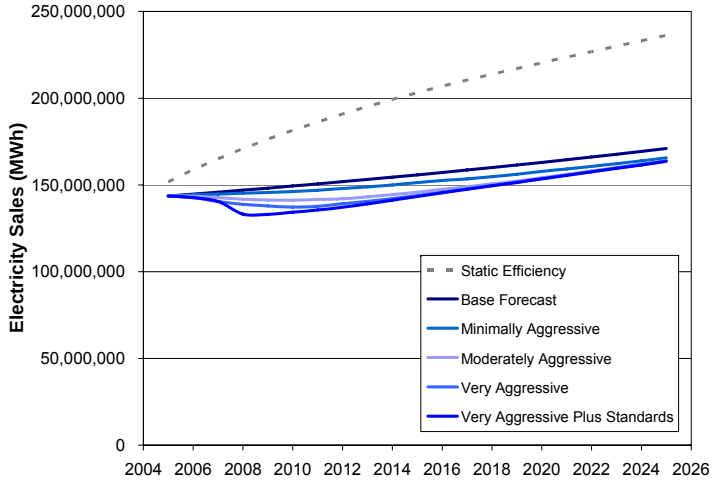


Figure 8. Achievable Potential Scenarios – 2005-2025 (Peak Demand)

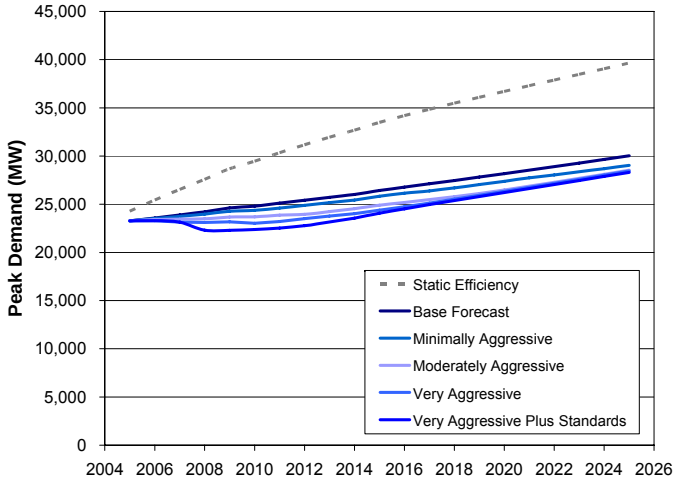


Figure 9. 2015 Achievable Potential by Sector (Electricity Sales)

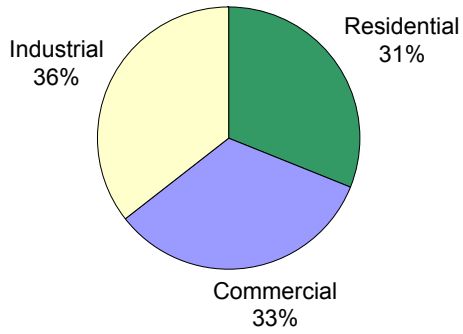


Figure 10. 2015 Achievable Potential by Sector (Peak Demand)

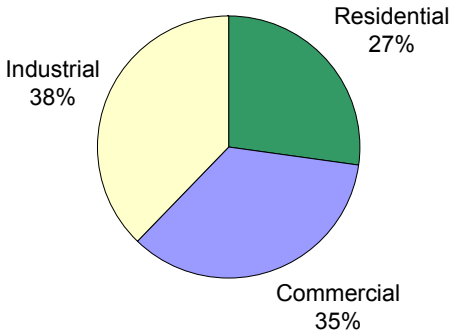


Figure 11. 2015 Achievable Potential by End Use (Electricity Sales)

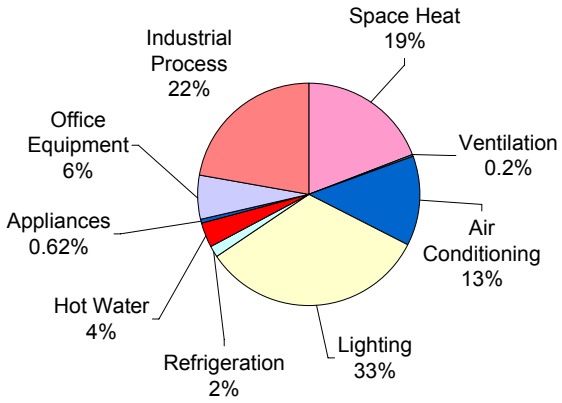


Figure 12. 2015 Achievable Potential by End Use (Peak Demand)

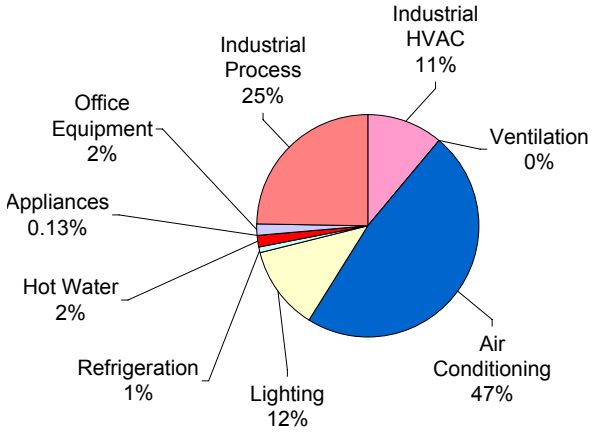


Figure 13. 2015 Achievable Potential by Sector and End Use (Electricity Sales)

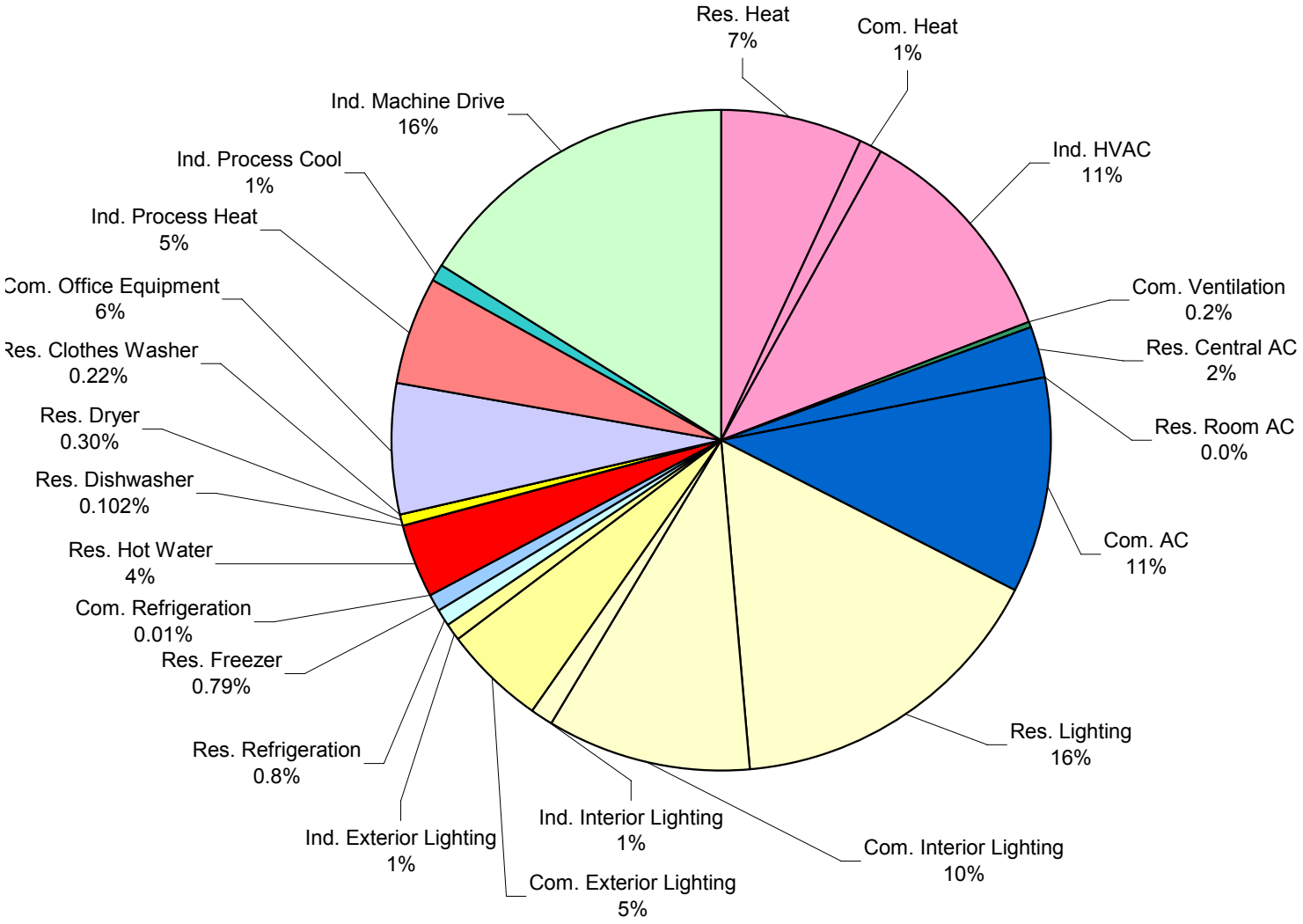
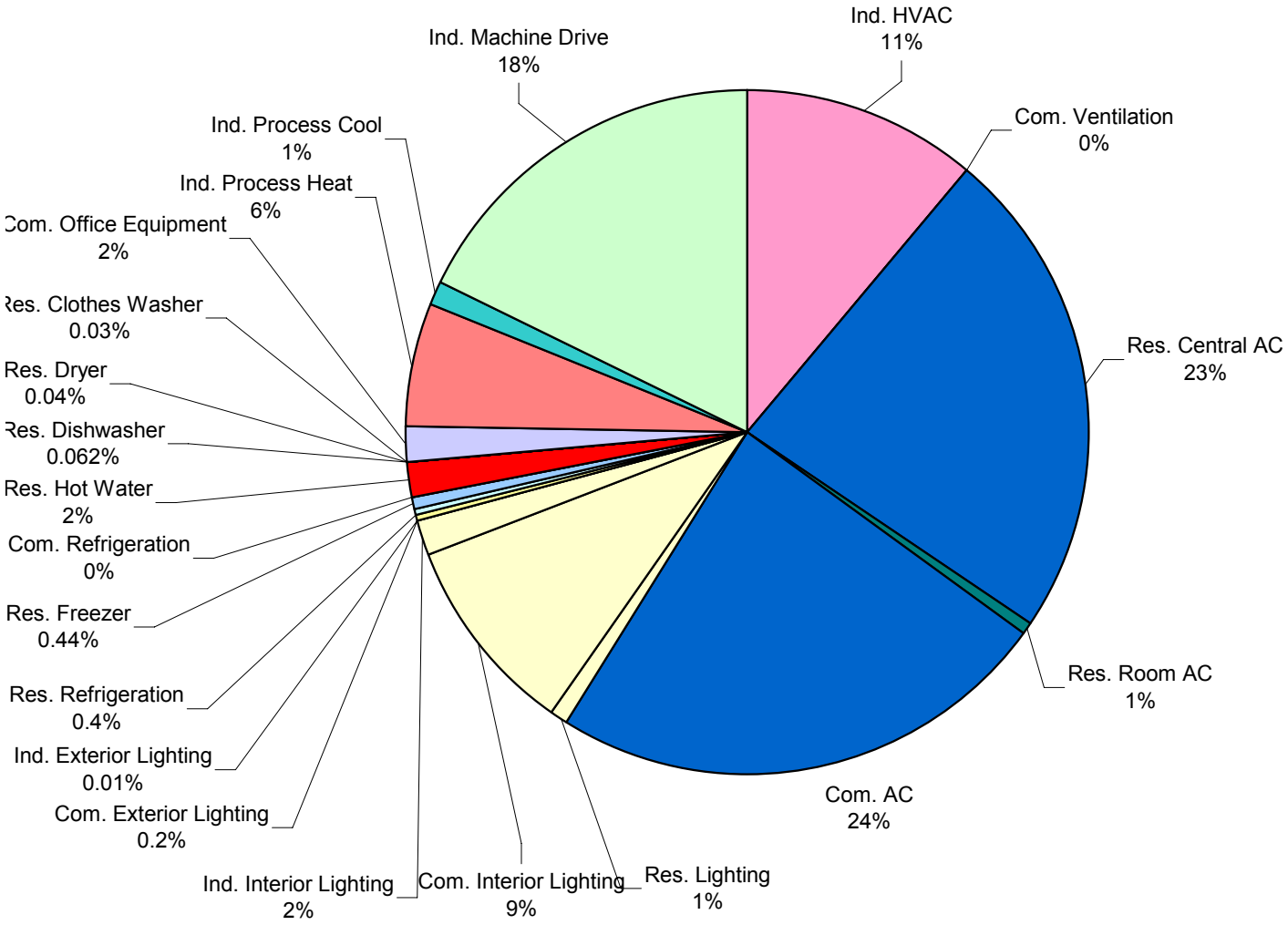


Figure 14. 2015 Achievable Potential by Sector and End Use (Peak Demand)



4.2. Experience-Based Approach

4.2.1. Summary of Other Assessments of Energy Efficiency Potential

- As noted above, we have reviewed approximately twenty assessments of energy efficiency potential and culled from those studies estimates of economic and achievable potential expressed in terms of percentage reductions from baseline sales and/or demand. The following table summarizes the range of results from these studies.

Table 8. Summary of Energy Efficiency Potential Studies

	Technical Potential	Economic Potential	Maximum Achievable Potential	Achievable Potential
Residential Sector	21%–36%	10.6%–30%	11%–35%	5.3%–21.7%
Commercial Sector	18%–41%	12.7%–35%	9%–39%	5.1%–17%
Industrial Sector	17%–38%	6.2%–32%	7%–60%	2%–19%

- These studies employ a variety of methodologies. The lower ends of the ranges presented tend to emerge from studies employing more formal accounting models with endogenous energy efficiency measure adoption functions. Thus, adoption is forecast using a general adoption algorithm as is used in this study, or as a function of program cost-effectiveness. The higher ends of the ranges are produced using methods that tend to reply on judgment-based estimates of adoption.
- For each of the studies identified, we calculated the savings percentage for the residential, commercial, and industrial sectors at five year intervals for twenty years. These savings percentages were then multiplied by ICF's projected the OPA baseline electricity sales for the respective years in order to arrive at the electricity usage that could plausibly be saved by Ontario customers. These savings estimates were then subtracted from the OPA's total baseline electricity to show predicted electricity sales under the extrapolated savings percentages.
- Given the wide range of savings potential estimates, the studies have been classified into two subsets based upon the type of potential estimated.
  - The first subset shows the potential electricity sales for Ontario based on the predicted savings percentages of studies identifying potential savings from **minimally to moderately aggressive programs**. There is significant variance between these studies in part because each study defines a minimally or moderately aggressive program differently. Also, in several cases these studies ignore potential efficiency savings in certain areas of the economy (i.e., residential lighting), or are limited to programs already in existence within the study area, reducing the overall savings identified.

– The second subset shows the potential electricity sales numbers for Ontario based on the predicted savings percentages of studies identifying the potential cost-effective savings for the study area or the **maximum achievable potential** from instituting a very aggressive program requiring large sustained investment. These studies represent the upper bounds of potential energy efficiency savings.

Table 9. Overview of Energy Efficiency Potential Studies and Program Experience

Historical Savings

		Total Savings Range (GWh)	Net Range (GWh)	% Savings Range
2010	Min	3,401	145,984	2.3%
	Max	4,914	144,471	3.3%
2015	Min	3,559	151,213	2.3%
	Max	11,237	143,535	7.3%
2020	Min	3,748	158,151	2.3%
	Max	18,795	143,104	11.6%
2025	Min	3,959	165,848	2.3%

Moderately Aggressive Achievable

		Total Savings Range (GWh)	Net Range (GWh)	% Savings Range
2010	Min	3,023	146,363	2.0%
	Max	8,963	140,422	6.0%
2015	Min	6,251	148,521	4.0%
	Max	18,573	136,199	12.0%
2020	Min	9,429	152,470	5.8%
	Max	25,904	135,995	16.0%
2025	Min	12,467	157,340	7.3%

Economic Potential

		Total Savings Range (GWh)	Net Range (GWh)	% Savings Range
2010	Min	10,756	138,630	7.2%
	Max	23,638	125,748	15.8%
2015	Min	20,894	133,878	13.5%
	Max	48,227	106,544	31.2%
2020	Min	27,221	134,678	16.8%
	Max	62,243	99,656	38.4%
2025	Min	33,018	136,789	19.4%
	Max	75,492	94,315	44.5%

Figure 15. Predicted Sales from Moderately Aggressive Achievable Studies

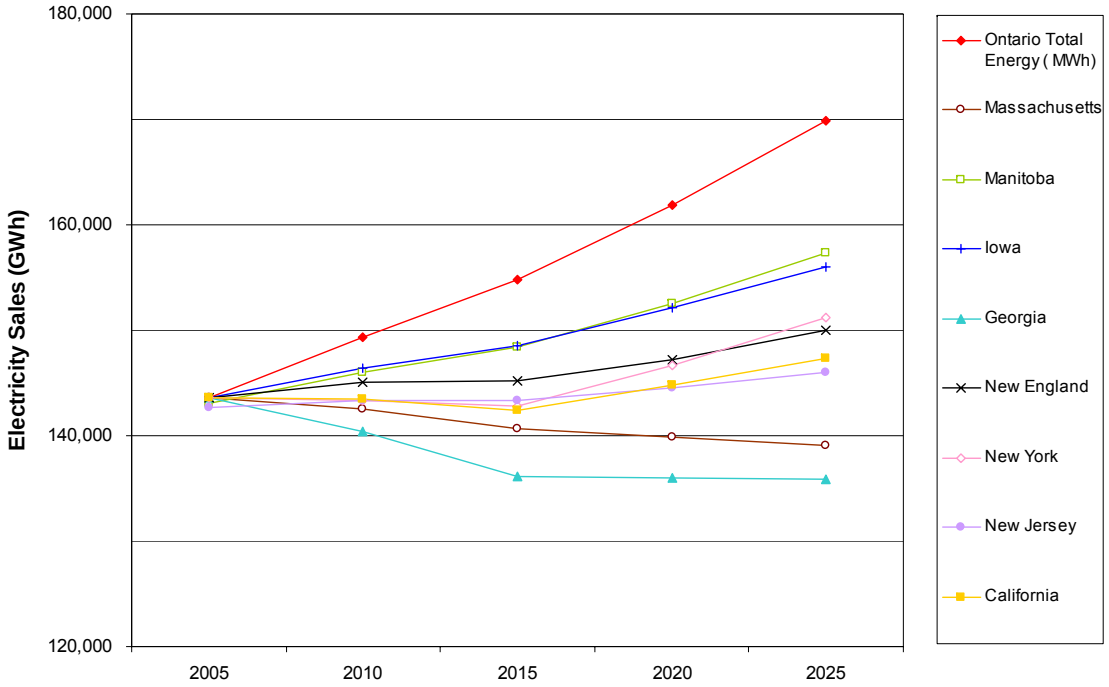
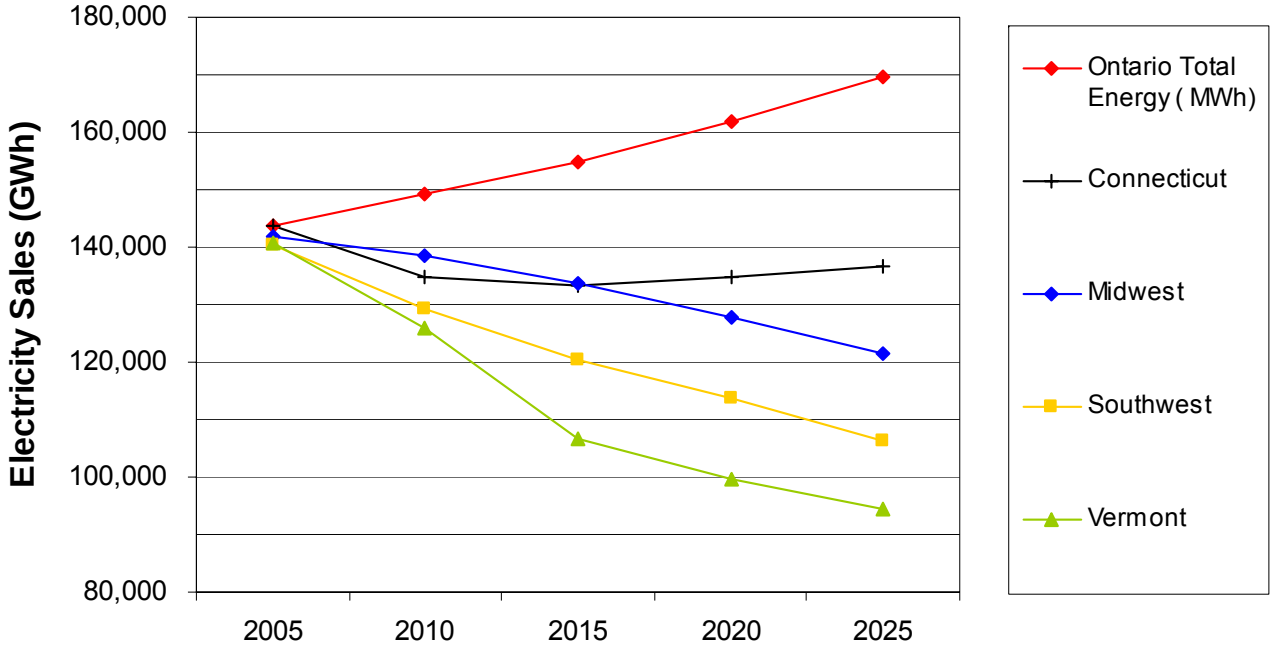


Figure 16. Predicted Sales from Economic Potential Studies



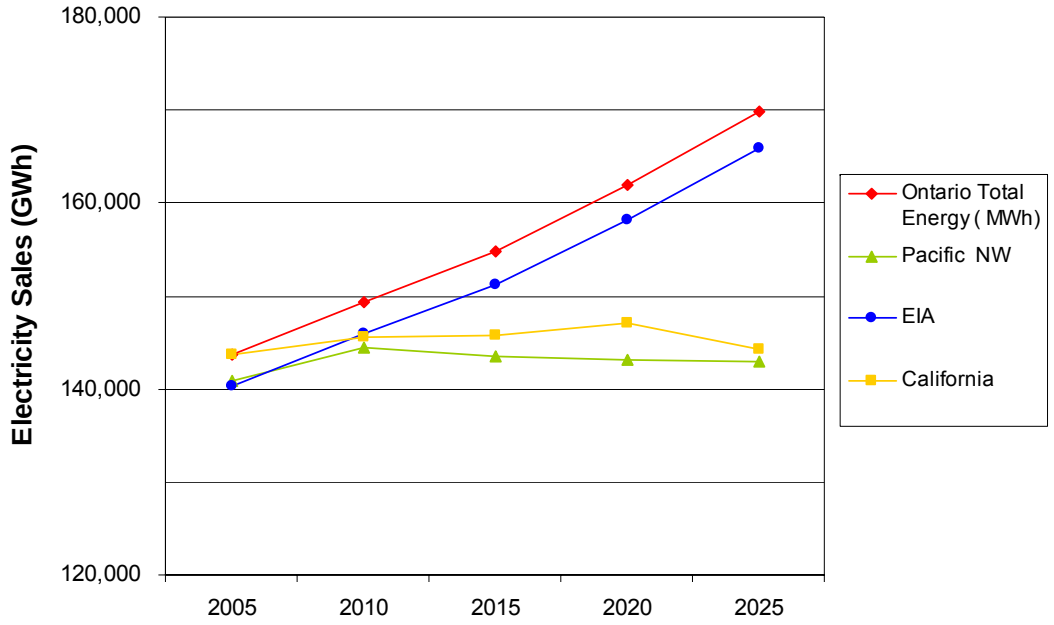
4.2.2. Summary of Program Experience

- As noted earlier, application of the impacts of individual best practice or exemplary programs to the Ontario situation is complicated by the fact that the program results tend to be reported in absolute rather than relative terms. Absent more detailed information regarding the duration of programs, funding profile and base sales and demand, this program experience cannot be applied in a manner that yields much insight in the Ontario context.
- As an alternative, we have gathered time series program impact data from three sources: (1) The Regional Technical Forum (Pacific Northwest); (2) The Energy Information Administration (pertaining to total US utility energy efficiency investment); and (3) The State of California. These impact data allow us to calculate relative reductions in annual sales and demand that can be applied to the forecast of Ontario load to yield a useful illustration of potential impact.
- The figure below illustrates the level of electricity sales in Ontario under scenarios based on these three sources of energy efficiency program experience.
- The Regional Technical Forum (RTF) reports data on annual electricity savings due to utility- or public benefits-funded energy efficiency programs, state building codes and federal appliance standards for the period 1981 through 2004 for the states comprising the Northwest Power Planning Council. These annual savings data were divided by historical annual retail sales for the same jurisdictions to yield percentage reductions in sales by year.
- The RTF data show actual energy savings growing from about 1.7 percent in 1984 to over 15 percent by 2004. These annual savings fractions were laid against our forecast of Ontario baseline sales to yield an estimate of the level of future sales in Ontario under circumstances that yield the same relative levels of savings.
- The EIA data show reported annual electricity savings by all US utilities for the period 1989 through 2003. However, the EIA data show the sometimes pronounced annual fluctuations produced by sudden increases or decreases in program funding. However, over the period covered, annual percentage decreases in electricity sales typically varied between one and two percent. For purposes of this exercise, we selected the maximum annual reduction in sales for each customer class, applied those to our forecast of Ontario class sales and summed the result.
- Similar to the Pacific Northwest, California has a long history of investment in energy efficiency. Data reported by the California Energy Commission show that since 1976, total electricity sales have been reduced by 15 percent relative what they otherwise would have been. Although the pattern of annual savings again shows wide fluctuations based on funding cycles, the California trend has been toward steadily increasing savings. For purposes of this exercise, we simply prepared a straight-line interpolation between an assumed savings level of 0 percent in 1976 to 15 percent in 2004. These annual numbers were then applied to the Ontario baseline forecast.
- This exercise clearly highlights the most important indicator of achievable potential – aggressive and sustained funding. As noted, the EIA data reflect the “average” experience of the US utility industry with energy efficiency investment; although there was a period during the late 1980s and early 1990s when funding and savings steadily increased, most utilities made relatively little investment and even that was not sustained.

Most of the US achievement in utility-driven energy efficiency can be traced to activity in California, Wisconsin, New York and the Pacific Northwest.

- The California and Pacific Northwest scenarios show very similar patterns of increasing savings over time. The levels of savings actually achieved over a 15 or 20 year period match fairly closely the high end of many estimates of achievable potential.
- Unfortunately, data showing the costs of the savings levels reported in the RTF are not available. However, the costs reported for the EIA savings data are slightly over $25 billion (US) for the period covered by the savings values, or approximately $0.04 (nominal US). Energy efficiency program spending data for California are incomplete. However, we estimate conservatively that, since 1975, approximately $5 billion (US) have been spent, though the program composition has shifted markedly from largely informational programs in the late 1970s to most rebate programs today. Since 1998, the average levelized cost of a conserved kWh has been slightly above $0.02 (US).

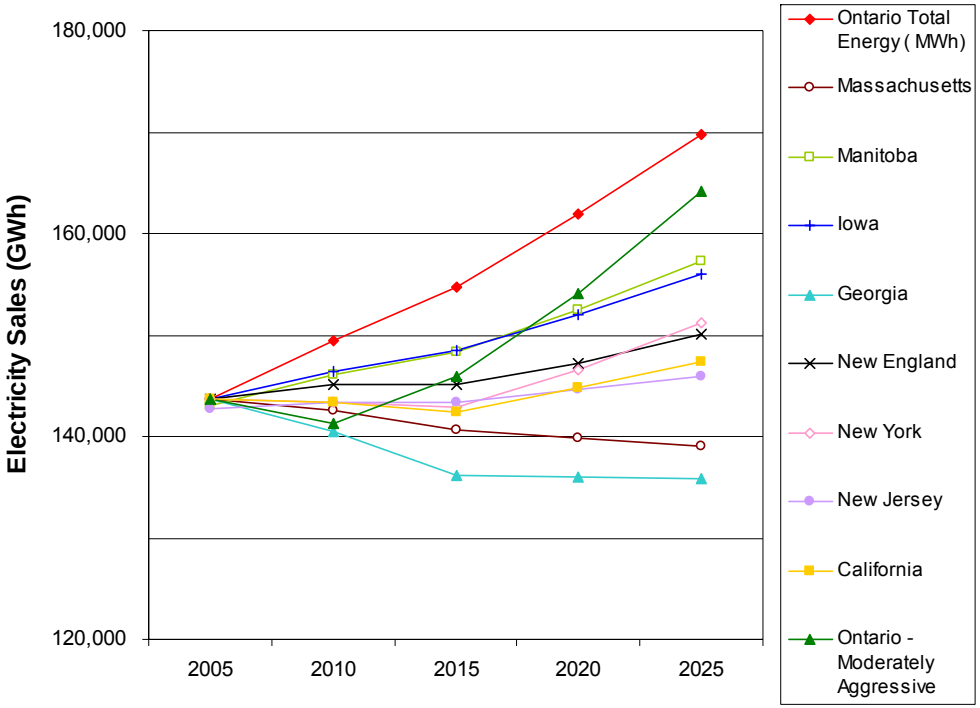
Figure 17. Ontario Electricity Sales Scenarios Based on Program Experience



4.2.3. Comparison with the Results from the Accounting Approach

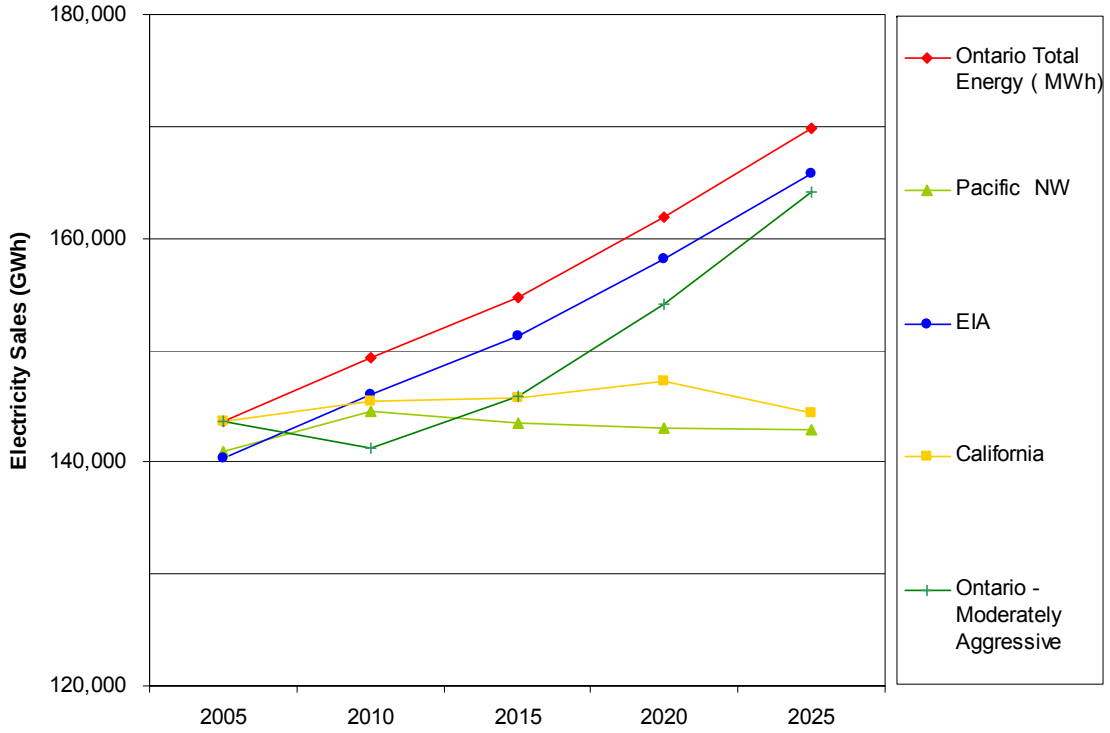
- The figures below show the results of the accounting model approach in the context of the results implied by other energy efficiency potential studies and historical program impacts. In general, the results of our EEPM analysis are consistent with the magnitude of savings projected or achieved in other contexts.
- In the below figure the Ontario base forecast and the results from the EEPM-generated moderately aggressive scenario are compared with the results from moderately aggressive scenarios from other potential estimate studies. The moderately aggressive scenario for Ontario takes into account naturally-occurring equipment turnover as well as emerging technologies. In contrast, the scenarios for other jurisdictions mainly extend a current forecast over the next 20 years. Therefore, the below figure should be used a guide, not as a strict comparison.

Figure 18. Ontario Electricity Sales Scenarios Based on Moderately Aggressive Achievable Studies



- The below figure may provide a more direct comparison between Ontario's moderately aggressive scenario and other program experiences. Ontario's moderately aggressive scenario achieves the greatest amount of savings over the first five years. Following this, a combination of equipment turnover and the convergence of an aggressive scenario with the naturally occurring scenario increases the sales forecast. Overall, the moderately aggressive scenario is comparable to the EIA scenario. In contrast, the scenarios for Pacific NW and California extend historical savings over the next 20 years.
- Notably, California and the Pacific Northwest have been unusual in the sustained level of emphasis they have placed on energy efficiency programs. Meeting nearly all load growth with energy efficiency, as is implied by the results of the California and Pacific NW data below, can result only from prolonged and intense engagement in energy efficiency.

Figure 19. Ontario Electricity Sales Scenarios Based on Program Experience



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5. Appendix: Detailed Accounting Model Outputs

Table 10. Electric base Forecasts and Achievable Potential Scenarios

Electric Base Forecast and Decrements - All Sectors

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	151,728,312	158,804,840	165,041,133	170,945,628	176,328,933	181,413,826	186,244,705	190,867,221	195,168,011	199,270,056	203,183,482	206,935,626	210,445,433	213,810,983	217,049,973	220,388,344	223,640,278	226,788,622	229,938,855	233,003,061	236,201,727
Base Forecast	143,627,011	144,725,376	145,850,102	147,001,491	148,179,850	149,385,497	150,618,756	151,879,961	153,169,451	154,487,578	155,834,699	157,211,181	158,617,398	160,053,736	161,520,588	163,018,356	164,547,453	166,108,299	167,701,326	169,326,974	170,985,694
Minimally Aggressive	143,627,011	144,344,801	144,748,779	145,279,135	145,625,300	146,207,525	146,917,941	147,929,387	148,883,851	150,032,804	151,296,634	152,601,665	153,472,367	154,743,685	156,155,448	157,755,491	159,154,459	160,671,596	162,275,302	163,884,791	165,661,370
Moderately Aggressive	143,627,011	143,541,479	142,679,802	141,781,109	141,280,207	141,183,025	141,604,849	141,981,471	143,173,597	144,398,531	145,848,460	147,399,696	148,947,694	150,556,175	152,231,463	154,141,169	156,082,520	158,018,322	160,009,780	162,010,654	164,127,152
Very Aggressive	143,627,011	142,692,308	140,449,732	138,864,671	137,896,030	137,225,627	137,688,532	139,100,462	140,556,249	142,132,736	143,887,495	145,813,446	147,756,403	149,698,261	151,611,913	153,674,082	155,704,042	157,688,460	159,743,652	161,758,691	163,883,757
Very Aggressive Plus Standards	143,627,011	142,692,308	140,449,732	133,223,154	133,058,746	134,256,320	135,542,047	137,171,550	139,075,793	141,161,593	143,295,747	145,439,898	147,484,508	149,468,931	151,398,373	153,465,480	155,495,635	157,478,344	159,531,057	161,545,677	163,669,738
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	24,271	25,441	26,532	27,587	28,672	29,464	30,340	31,167	31,954	32,683	33,492	34,196	34,855	35,488	36,098	36,702	37,292	37,874	38,467	39,051	39,653
Base Forecast	23,268	23,583	23,889	24,210	24,623	24,804	25,106	25,409	25,723	26,022	26,430	26,769	27,113	27,461	27,813	28,170	28,531	28,898	29,269	29,644	30,025
Minimally Aggressive	23,268	23,529	23,741	23,971	24,261	24,366	24,611	24,887	25,159	25,441	25,824	26,145	26,384	26,693	27,034	27,389	27,734	28,046	28,372	28,697	29,040
Moderately Aggressive	23,268	23,417	23,455	23,484	23,674	23,691	23,865	23,966	24,237	24,537	24,899	25,193	25,480	25,782	26,117	26,490	26,877	27,273	27,688	28,107	28,538
Very Aggressive	23,268	23,299	23,137	23,096	23,185	23,018	23,207	23,510	23,778	24,026	24,385	24,736	25,126	25,530	25,935	26,353	26,765	27,174	27,599	28,020	28,452
Very Aggressive Plus Standards	23,268	23,299	23,137	22,310	22,301	22,369	22,533	22,774	23,153	23,565	24,071	24,523	24,959	25,382	25,794	26,214	26,627	27,035	27,460	27,880	28,311

Residential Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	44,120,265	44,854,459	45,344,096	45,862,487	46,405,096	46,966,100	47,542,819	48,118,166	48,688,458	49,244,358	49,776,548	50,276,148	50,722,932	51,124,537	51,477,474	51,761,177	51,996,633	52,183,487	52,322,918	52,417,494	52,470,959
Base Forecast	42,230,046	41,986,136	41,747,592	41,514,356	41,286,371	41,063,583	40,845,936	40,633,378	40,425,857	40,223,323	40,025,725	39,833,017	39,645,149	39,462,077	39,283,756	39,110,141	38,941,189	38,776,860	38,617,111	38,461,904	38,311,200
Minimally Aggressive	42,230,046	41,929,456	41,567,253	41,145,587	40,668,284	40,171,661	39,679,688	39,231,032	38,842,546	38,535,546	38,317,158	38,179,786	38,094,251	38,050,361	38,026,620	37,992,378	37,889,414	37,750,244	37,595,401	37,417,103	37,222,096
Moderately Aggressive	42,230,046	41,800,329	41,134,685	40,243,525	39,273,786	38,371,801	37,701,181	37,308,788	37,148,937	36,982,211	36,908,261	36,868,983	36,792,312	36,706,189	36,632,730	36,561,548	36,504,008	36,449,603	36,389,520	36,355,836	36,308,822
Very Aggressive	42,230,046	41,648,840	40,599,490	39,266,243	38,011,099	37,178,362	36,548,053	36,313,896	36,235,513	36,156,834	36,109,106	36,111,313	36,143,442	36,186,923	36,224,068	36,233,061	36,226,011	36,201,299	36,196,183	36,172,797	36,133,290
Very Aggressive Plus Standards	42,230,046	41,648,840	40,599,490	38,243,414	36,886,547	36,197,212	35,806,070	35,646,705	35,653,025	35,725,560	35,820,370	35,916,328	35,992,792	36,054,369	36,097,619	36,108,385	36,101,262	36,075,899	36,070,034	36,045,967	36,005,892
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	5,950	6,086	6,214	6,341	6,486	6,573	6,692	6,798	6,903	6,999	7,112	7,201	7,279	7,347	7,405	7,425	7,439	7,449	7,454	7,455	7,454
Base Forecast	5,801	5,796	5,787	5,781	5,796	5,755	5,742	5,727	5,715	5,699	5,705	5,695	5,685	5,675	5,665	5,656	5,646	5,636	5,627	5,617	5,608
Minimally Aggressive	5,801	5,789	5,768	5,743	5,720	5,653	5,617	5,578	5,546	5,520	5,527	5,529	5,539	5,556	5,575	5,579	5,579	5,542	5,498	5,448	5,395
Moderately Aggressive	5,801	5,775	5,722	5,630	5,566	5,446	5,376	5,329	5,316	5,300	5,288	5,249	5,202	5,158	5,137	5,110	5,093	5,083	5,074	5,069	5,064
Very Aggressive	5,801	5,758	5,639	5,519	5,408	5,276	5,218	5,187	5,135	5,062	5,010	4,975	4,979	4,997	5,018	5,018	5,017	5,014	5,013	5,009	5,004
Very Aggressive Plus Standards	5,801	5,758	5,639	5,405	5,206	4,968	4,792	4,684	4,691	4,723	4,776	4,816	4,851	4,881	4,905	4,907	4,906	4,902	4,900	4,896	4,891

Commercial Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	58,372,767	62,187,513	65,663,467	69,002,955	71,976,923	74,789,500	77,468,507	80,055,051	82,449,062	84,752,484	86,973,866	89,123,452	91,211,489	93,248,110	95,244,387	97,199,387	99,154,601	101,053,474	103,020,399	104,954,849	106,890,162
Base Forecast	54,554,001	55,409,577	56,281,092	57,168,852	58,073,169	58,994,361	59,932,754	60,888,678	61,862,471	62,854,477	63,865,048	64,894,541	65,943,321	67,011,761	68,100,239	69,209,143	70,338,868	71,489,815	72,662,396	73,857,028	75,074,139
Minimally Aggressive	54,554,001	55,230,977	55,709,270	56,364,491	56,860,912	57,520,746	58,269,817	59,168,390	60,121,352	61,161,929	62,234,042	63,384,184	64,222,432	65,286,437	66,472,987	67,632,104	68,650,359	69,779,988	70,967,879	72,145,287	73,337,894
Moderately Aggressive	54,554,001	54,856,693	54,756,607	54,751,487	54,983,154	55,511,367	56,333,563	57,004,579	58,080,959	59,262,058	60,536,786	61,763,488	62,967,486	64,169,082	65,382,363	66,599,758	67,838,959	69,070,075	70,363,949	71,644,474	72,930,726
Very Aggressive	54,554,001	54,465,328	53,709,992	53,535,369	53,659,180	53,848,194	54,634,805	56,074,812	57,394,374	58,694,521	60,002,969	61,320,599	62,634,837	63,935,523	65,222,300	66,486,717	67,752,659	68,997,688	70,298,139	71,581,579	72,868,756
Very Aggressive Plus Standards	54,554,001	54,465,328	53,709,992	50,677,641	51,298,036	52,792,738	54,210,412	55,648,800	57,044,448	58,446,648	59,837,598	61,205,511	62,545,657	63,858,366	65,150,112	66,416,028	67,681,749	68,925,692	70,224,567	71,508,496	72,795,825
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	10,321	10,939	11,526	12,106	12,691	13,145	13,630	14,095	14,536	14,949	15,399	15,800	16,190	16,570	16,944	17,312	17,678	18,043	18,426	18,804	19,178
Base Forecast	9,815	10,017	10,218	10,427	10,677	10,828	11,033	11,240	11,454	11,662	11,921	12,151	12,385	12,622	12,863	13,108	13,356	13,609	13,866	14,127	14,391
Minimally Aggressive	9,815	9,991	10,140	10,307	10,499	10,613	10,793	10,993	11,209	11,430	11,689	11,928	12,113	12,333	12,585	12,828	13,065	13,300	13,552	13,802	14,051
Moderately Aggressive	9,815	9,937	10,000	10,076	10,225	10,328	10,503	10,622	10,837	11,097	11,383	11,633	11,877	12,121	12,368	12,617	12,871	13,127	13,400	13,672	13,941
Very Aggressive	9,815	9,881	9,859	9,905	10,017	9,999	10,181	10,460	10,721	10,971	11,260	11,526	11,793	12,058	12,321	12,581	12,841	13,100	13,374	13,647	13,916
Very Aggressive Plus Standards	9,815	9,881	9,859	9,492	9,556	9,810	10,089	10,366	10,641	10,910	11,216	11,493	11,765	12,033	12,298	12,558	12,818	13,076	13,350	13,622	13,891

Industrial Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	49,235,281	51,762,868	54,033,571	56,080,186	57,946,914	59,658,226	61,233,379	62,694,005	64,030,491	65,273,215	66,433,068	67,536,026	68,511,011	69,438,337	70,328,112	71,427,780	72,498,044	73,551,661	74,595,538	75,630,718	76,840,605
Base Forecast	46,842,965	47,329,663	47,821,418	48,318,283	48,820,310	49,327,553	49,840,066	50,357,904	50,881,123	51,409,778	51,943,926	52,483,623	53,028,928	53,579,898	54,136,594	54,699,073	55,267,396	55,841,624	56,421,819	57,008,042	57,600,355
Minimally Aggressive	46,842,965	47,184,368	47,472,256	47,769,057	48,096,104	48,515,118	48,968,436	49,529,965	49,919,953	50,335,330	50,745,434	51,037,695	51,155,684	51,406,888	51,655,841	52,131,009	52,614,686	53,141,364	53,712,021	54,322,401	55,101,381
Moderately Aggressive	46,842,965	46,884,458	46,788,510	46,786,097	47,023,266	47,299,857	47,570,104	47,668,104	47,943,701	48,154,262	48,403,413	48,767,225	49,187,896	49,680,903	50,216,371	50,979,863	51,739,552	52,498,645	53,256,311	54,010,345	54,887,604
Very Aggressive	46,842,965	46,578,140	46,140,250	46,063,059	46,225,752	46,199,072	46,505,674	46,711,754	46,926,362	47,281,381	47,775,420	48,381,534	48,978,123	49,575,816	50,165,545	50,954,304	51,725,372	52,489,473	53,249,330	54,004,316	54,881,711
Very Aggressive Plus Standards	46,842,965	46,578,140	46,140,250	44,302,100	44,874,163	45,266,371	45,525,565	45,876,045	46,378,320	46,989,385	47,637,779	48,318,059	48,946,059	49,556,196	50,150,642	50,941,068	51,712,624	52,476,753	53,236,456	53,991,214	54,868,021
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	8,000	8,416	8,792	9,140	9,495	9,747	10,019	10,274	10,515	10,735	10,981	11,194	11,386	11,571	11,749	11,965	12,175	12,382	12,588	12,792	13,020
Base Forecast	7,652	7,769	7,883	8,002	8,150	8,221	8,331	8,441	8,554	8,661	8,804	8,923	9,043	9,163	9,285	9,407	9,529	9,652	9,776	9,901	10,026
Minimally Aggressive	7,652	7,748	7,832	7,921	8,042	8,100	8,201	8,316	8,404	8,491	8,609	8,688	8,732	8,803	8,874	8,982	9,091	9,204	9,322	9,446	9,593
Moderately Aggressive	7,652	7,705	7,732	7,778	7,883	7,917	7,986	8,015	8,085	8,140	8,228	8,312	8,402	8,504	8,613	8,763	8,912	9,063	9,214	9,365	9,533
Very Aggressive	7,652	7,660	7,639	7,673	7,761	7,743	7,808	7,864	7,922	7,993	8,114	8,234	8,354	8,475	8,596	8,753	8,907	9,060	9,212	9,364	9,532
Very Aggressive Plus Standards	7,652	7,660	7,639	7,413	7,538	7,591	7,652	7,724	7,821	7,932	8,079	8,214	8,342	8,468	8,591	8,749	8,904	9,057	9,210	9,361	9,530

Figure 20. Residential Sector Achievable Potential Scenarios (Electricity Sales)

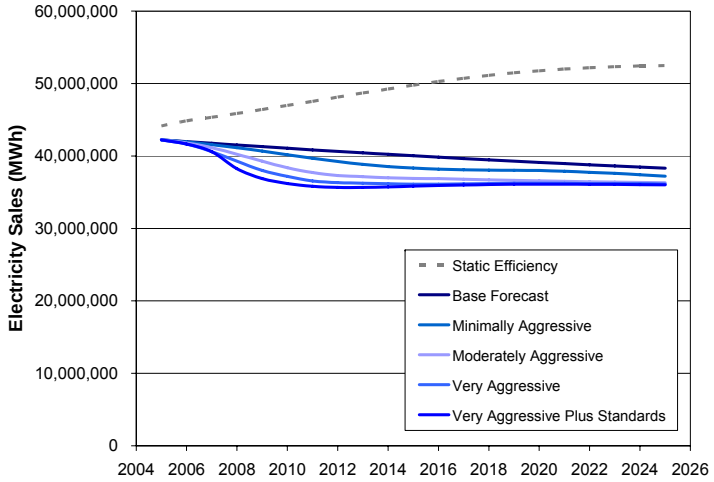

Figure 21. Residential Sector Achievable Potential Scenarios (Peak Demand)

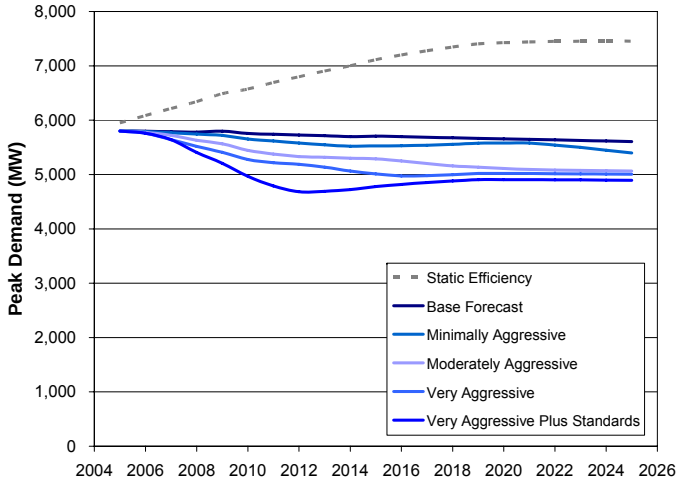

Figure 22. 2015 Residential Sector Achievable Potential by End Use (Moderately Aggressive, Electricity Sales)

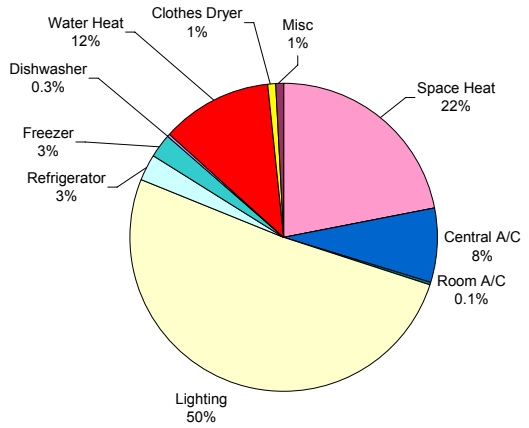

Figure 23. 2015 Residential Sector Achievable Potential by End Use (Moderately Aggressive, Peak Demand)

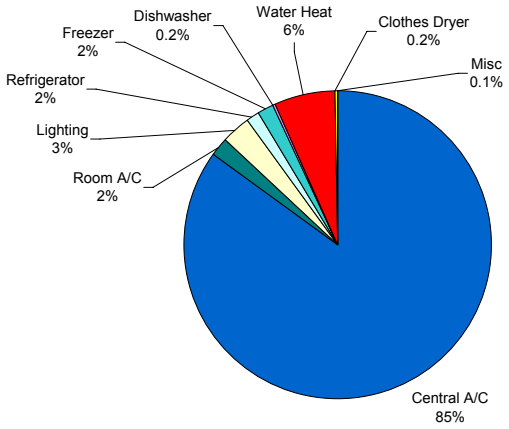

Table 11. Residential Sector Results by End Use

Minimally Aggressive Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	8,425	31,922	70,090	120,440	178,209	236,701	288,315	326,102	345,375	344,738	326,115	293,820	253,177	209,276	170,541	166,533	157,110	143,698	138,823	140,711
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	3,547	11,212	23,227	39,269	58,272	78,377	97,091	111,722	119,999	120,680	113,875	100,955	84,088	65,642	54,535	43,827	52,135	64,812	81,045	99,671
Room A/C	-	224	416	505	7,664	6,435	2,216	2,348	2,476	2,575	2,623	2,605	2,521	2,384	2,214	2,033	1,861	1,711	1,587	1,491	1,421
Lighting	-	29,824	93,448	192,098	322,773	477,133	641,396	797,834	927,960	1,016,644	1,055,643	1,045,035	992,019	907,913	804,878	693,619	582,400	477,019	381,213	297,117	225,638
Refrigerator	-	541	1,388	2,336	3,225	3,942	4,416	(8,649)	(17,923)	(23,131)	(24,042)	(20,491)	(945)	20,646	44,096	69,077	95,140	121,744	148,307	174,249	199,031
Freezer	-	77	198	334	461	564	632	1,559	3,815	7,579	13,019	20,273	28,593	38,209	49,060	61,000	73,809	87,208	100,883	114,511	127,780
Dishwasher	-	-	555	1,630	3,102	4,754	6,306	7,476	8,053	7,959	7,270	6,176	4,907	3,661	2,643	1,787	1,121	637	306	95	(30)
Water Heat	-	13,868	40,726	77,705	119,917	160,998	194,252	214,169	217,797	205,403	180,143	146,902	110,864	76,365	46,314	23,875	37,101	70,136	112,992	160,682	209,512
Clothes Dryer	-	41	108	189	271	346	406	500	1,121	2,344	4,243	6,879	10,297	14,456	19,122	24,239	29,723	35,465	41,342	47,226	52,992
Misc	-	134	364	653	965	1,270	1,546	1,703	2,188	3,029	4,250	5,862	7,867	10,816	13,892	17,056	20,260	23,450	26,569	29,561	32,378
Total	-	56,680	180,338	368,769	618,087	891,921	1,166,248	1,402,346	1,583,311	1,687,777	1,708,567	1,653,230	1,550,898	1,411,716	1,257,135	1,117,763	1,051,776	1,026,615	1,021,710	1,044,801	1,089,104

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	4.5	14.2	29.5	50.0	74.2	99.9	124.0	142.9	153.5	154.1	144.1	124.8	99.0	69.9	56.1	43.0	64.2	92.3	125.6	162.2
Room A/C	-	0.5	0.9	1.1	13.8	10.8	3.8	4.0	4.3	4.4	4.5	4.4	4.2	3.9	3.5	3.2	2.8	2.5	2.2	2.0	1.9
Lighting	-	0.2	0.8	1.6	2.6	3.9	5.2	6.4	7.4	8.1	8.3	8.2	7.7	6.9	6.1	5.1	4.2	3.4	2.6	2.0	1.4
Refrigerator	-	0.1	0.1	0.2	0.3	0.4	0.4	(1.1)	(2.2)	(3.0)	(3.2)	(3.1)	(1.2)	0.8	3.0	5.3	7.8	10.2	12.7	15.1	17.4
Freezer	-	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.5	1.0	1.6	2.4	3.2	4.2	5.2	6.3	7.5	8.6	9.8	10.9
Dishwasher	-	-	0.1	0.2	0.3	0.5	0.6	0.7	0.8	0.8	0.7	0.6	0.4	0.3	0.2	0.1	0.1	0.0	(0.0)	(0.0)	(0.0)
Water Heat	-	1.0	3.0	5.8	8.9	11.8	14.1	15.4	15.5	14.4	12.4	9.9	7.2	4.6	2.4	0.8	2.0	4.9	8.6	12.6	16.7
Clothes Dryer	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1
Misc	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.6	0.6	0.7
Total	-	6.4	19.2	38.4	76.0	101.7	124.2	149.6	168.9	178.7	178.0	165.9	145.8	119.3	90.0	76.7	67.2	94.0	128.5	168.8	212.2

Moderately Aggressive Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	27,419	106,744	236,039	394,292	544,430	649,930	693,673	681,706	714,920	688,033	615,838	556,221	506,761	463,534	428,446	394,487	362,629	334,117	309,715	289,570
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	11,692	38,766	82,050	136,595	191,146	232,553	252,541	250,722	242,696	241,579	246,980	256,351	264,953	265,596	268,758	268,076	265,623	263,085	261,268	260,408
Room A/C	-	623	1,074	11,094	9,104	8,167	4,286	4,646	4,807	4,739	4,504	4,184	3,845	3,522	3,232	2,982	2,774	2,606	2,475	2,378	2,308
Lighting	-	98,651	323,079	671,643	1,091,033	1,482,288	1,751,196	1,862,437	1,842,215	1,739,503	1,594,446	1,431,105	1,262,331	1,095,289	934,581	783,559	644,778	520,097	410,678	316,978	238,775
Refrigerator	-	1,553	3,803	6,070	(5,503)	(10,645)	(7,991)	3,341	23,253	50,525	83,174	119,061	166,372	211,731	254,328	293,673	329,500	361,681	390,176	390,751	389,156
Freezer	-	222	544	868	2,030	5,820	12,992	24,090	39,188	57,787	78,977	101,730	124,509	146,764	168,021	187,974	206,430	223,276	238,444	242,630	245,460
Dishwasher	-	-	1,820	5,504	10,312	14,719	17,178	17,177	15,382	12,819	10,189	7,803	5,765	4,094	2,847	1,876	1,153	641	297	81	(44)
Water Heat	-	45,140	135,760	255,335	371,273	449,606	473,549	448,512	392,036	379,055	364,560	371,513	397,452	428,329	450,702	460,274	457,033	446,881	434,673	422,965	412,597
Clothes Dryer	-	119	302	501	725	1,969	4,535	8,650	14,366	21,515	29,765	38,733	48,076	57,485	66,560	75,175	83,246	90,719	97,559	103,744	109,259
Misc	-	389	1,014	1,726	2,726	4,285	6,527	9,523	13,245	17,553	22,238	27,085	31,916	36,959	41,624	45,877	49,703	53,104	56,086	55,559	54,890
Total	-	185,807	612,906	1,270,831	2,012,586	2,691,782	3,144,755	3,324,590	3,276,920	3,241,112	3,117,464	2,964,033	2,852,837	2,755,888	2,651,026	2,548,593	2,437,181	2,327,257	2,227,591	2,106,069	2,002,378

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	14.9	49.4	105.0	176.6	249.6	307.9	339.7	342.2	339.7	354.6	378.8	409.2	435.9	441.0	453.4	456.7	455.2	452.1	449.3	447.3
Room A/C	-	1.5	2.4	20.4	16.4	14.1	7.7	8.4	8.6	8.4	7.9	7.3	6.5	5.9	5.3	4.8	4.3	4.0	3.7	3.5	3.3
Lighting	-	0.8	2.7	5.5	8.9	12.1	14.2	14.9	14.7	13.7	12.5	11.1	9.7	8.3	7.0	5.8	4.7	3.7	2.8	2.1	1.5
Refrigerator	-	0.2	0.4	0.6	(0.6)	(1.6)	(1.7)	(0.9)	0.8	3.1	6.3	9.6	14.1	18.4	22.4	26.1	29.4	32.4	35.0	34.7	34.3
Freezer	-	0.0	0.1	0.1	0.2	0.4	1.0	2.0	3.3	4.8	6.8	8.8	10.8	12.7	14.6	16.3	17.9	19.3	20.6	20.9	21.0
Dishwasher	-	-	0.2	0.5	1.0	1.5	1.7	1.7	1.5	1.2	1.0	0.7	0.5	0.3	0.2	0.1	0.1	0.0	(0.0)	(0.0)	(0.0)
Water Heat	-	3.4	10.1	18.9	27.5	32.9	34.3	32.1	27.7	26.7	26.5	27.9	30.7	33.8	36.0	37.0	36.8	35.9	34.9	33.8	32.9
Clothes Dryer	-	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0	2.1	2.2	2.3
Misc	-	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.2	1.2	1.2
Total	-	20.7	65.2	151.1	230.2	309.0	365.4	398.3	399.2	398.6	416.8	445.5	483.3	517.5	528.9	546.1	552.7	553.6	552.4	547.7	543.7

Residential Sector Results by End Use *(continued)*

Very Aggressive Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	49,324	194,032	417,586	647,437	802,133	1,003,039	1,045,345	969,707	899,670	830,217	757,717	683,836	612,409	546,639	493,103	446,480	406,915	374,068	347,308	325,853
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	21,357	73,129	151,941	234,619	293,441	317,307	316,222	324,947	342,037	358,481	363,391	352,499	336,246	319,711	311,542	304,793	299,806	296,531	294,772	294,286
Room A/C	-	958	15,959	12,876	11,312	10,672	6,734	6,713	6,436	6,053	5,647	5,251	4,882	4,548	4,254	4,002	3,792	3,624	3,493	3,396	3,326
Lighting	-	180,821	608,413	1,220,484	1,787,247	2,109,024	2,183,357	2,110,554	1,971,119	1,804,807	1,628,426	1,449,612	1,272,802	1,101,339	938,095	785,590	645,938	520,749	411,038	317,173	238,877
Refrigerator	-	2,459	5,717	(4,927)	(6,040)	5,285	29,382	63,198	102,326	143,237	183,834	223,076	270,234	313,510	352,877	388,361	420,017	447,909	447,417	444,841	440,220
Freezer	-	352	818	2,116	7,531	18,612	35,708	57,489	81,888	107,193	132,355	156,831	179,765	201,139	220,884	238,966	255,368	270,079	273,855	276,324	277,501
Dishwasher	-	-	3,307	10,076	17,674	22,039	22,002	19,470	16,266	13,141	10,317	7,860	5,791	4,106	2,852	1,877	1,154	641	297	81	(45)
Water Heat	-	81,213	244,726	434,321	567,758	608,851	674,263	660,796	662,904	680,102	681,758	657,507	617,155	573,205	532,880	500,370	473,666	452,231	435,152	421,457	410,252
Clothes Dryer	-	190	459	752	2,638	6,733	13,203	21,566	31,046	40,990	50,992	60,839	70,427	79,661	88,303	96,330	103,727	110,482	116,586	122,031	126,812
Misc	-	622	1,542	2,889	5,096	8,429	12,886	18,130	23,705	29,258	34,593	39,621	44,315	48,991	53,194	56,939	60,244	63,126	62,493	61,726	60,827
Total	-	337,295	1,148,102	2,248,113	3,275,272	3,885,221	4,297,883	4,319,482	4,190,345	4,066,488	3,916,619	3,721,704	3,501,707	3,275,154	3,059,688	2,877,080	2,715,178	2,575,561	2,420,928	2,289,108	2,177,910
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	27.2	93.4	196.1	309.0	394.4	436.6	450.3	484.7	535.2	587.6	611.4	595.9	567.1	536.3	525.3	515.8	508.5	503.2	499.6	497.4
Room A/C	-	2.3	30.6	23.8	20.7	18.9	12.4	12.3	11.7	10.9	10.0	9.2	8.4	7.8	7.1	6.6	6.2	5.8	5.6	5.3	5.2
Lighting	-	1.5	5.0	10.0	14.7	17.2	17.6	16.9	15.7	14.2	12.8	11.3	9.8	8.4	7.0	5.8	4.7	3.7	2.8	2.1	1.5
Refrigerator	-	0.2	0.6	(0.7)	(0.8)	(0.4)	1.7	4.7	8.2	11.9	15.9	19.5	23.9	28.0	31.7	35.0	37.9	40.5	40.1	39.5	38.8
Freezer	-	0.0	0.1	0.2	0.7	1.5	3.0	4.9	7.0	9.2	11.5	13.7	15.7	17.6	19.3	20.8	22.2	23.5	23.7	23.8	23.8
Dishwasher	-	-	0.3	1.0	1.8	2.2	2.1	1.9	1.6	1.2	1.0	0.7	0.5	0.3	0.2	0.1	0.1	0.0	(0.0)	(0.0)	(0.0)
Water Heat	-	6.1	18.2	32.2	42.0	44.5	49.1	48.7	50.0	52.4	53.6	52.1	49.2	45.8	42.7	40.2	38.0	36.3	34.9	33.7	32.7
Clothes Dryer	-	0.0	0.0	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1	2.2	2.4	2.5	2.6	2.7
Misc	-	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.3
Total	-	37.3	148.2	262.7	388.2	478.6	523.2	540.6	580.1	636.4	694.3	720.0	705.9	677.8	647.4	637.2	628.5	622.0	614.1	608.0	603.4

Very Aggressive Plus Aggressive Standards

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	49,324	194,032	900,610	1,256,125	1,270,160	1,240,407	1,176,480	1,093,676	1,002,616	910,060	820,375	736,375	659,823	591,742	537,208	490,223	450,536	417,620	390,768	369,168
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	21,357	73,129	181,530	300,043	415,625	503,480	545,969	533,051	508,465	482,385	457,266	434,366	414,363	397,629	390,105	384,418	380,555	378,359	377,608	378,062
Room A/C	-	958	15,959	12,876	11,312	10,672	6,734	6,713	6,436	6,053	5,647	5,251	4,882	4,548	4,254	4,002	3,792	3,624	3,493	3,396	3,326
Lighting	-	180,821	608,413	1,220,484	1,787,247	2,109,024	2,183,357	2,110,554	1,971,119	1,804,807	1,628,426	1,449,612	1,272,802	1,101,339	938,095	785,590	645,938	520,749	411,038	317,173	238,877
Refrigerator	-	2,459	5,717	(4,927)	(6,040)	5,285	29,382	63,198	102,326	143,237	183,834	223,076	270,234	313,510	352,877	388,361	420,017	447,909	447,417	444,841	440,220
Freezer	-	352	818	2,116	7,531	18,612	35,708	57,489	81,888	107,193	132,355	156,831	179,765	201,139	220,884	238,966	255,368	270,079	273,855	276,324	277,501
Dishwasher	-	-	3,307	10,076	17,674	22,039	22,002	19,470	16,266	13,141	10,317	7,860	5,791	4,106	2,852	1,877	1,154	641	297	81	(45)
Water Heat	-	81,213	244,726	944,537	1,018,199	999,791	992,705	967,104	913,319	842,003	766,747	695,959	633,400	580,228	536,308	502,377	475,048	453,261	435,920	421,990	410,559
Clothes Dryer	-	190	459	752	2,638	6,733	13,203	21,566	31,046	40,990	50,992	60,839	70,427	79,661	88,303	96,330	103,727	110,482	116,586	122,031	126,812
Misc	-	622	1,542	2,889	5,096	8,429	12,886	18,130	23,705	29,258	34,593	39,621	44,315	48,991	53,194	56,939	60,244	63,126	62,493	61,726	60,827
Total	-	337,295	1,148,102	3,270,942	4,399,824	4,866,371	5,039,866	4,986,674	4,772,832	4,497,763	4,205,355	3,916,689	3,652,357	3,407,709	3,186,137	3,001,756	2,839,927	2,700,961	2,547,077	2,415,937	2,305,307
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	27.2	93.4	271.9	475.5	671.4	835.6	926.6	906.8	860.3	814.9	767.0	722.7	683.2	649.2	637.3	627.8	620.7	615.7	612.4	610.4
Room A/C	-	2.3	30.6	23.8	20.7	18.9	12.4	12.3	11.7	10.9	10.0	9.2	8.4	7.8	7.1	6.6	6.2	5.8	5.6	5.3	5.2
Lighting	-	1.5	5.0	10.0	14.7	17.2	17.6	16.9	15.7	14.2	12.8	11.3	9.8	8.4	7.0	5.8	4.7	3.7	2.8	2.1	1.5
Refrigerator	-	0.2	0.6	(0.7)	(0.8)	(0.4)	1.7	4.7	8.2	11.9	15.9	19.5	23.9	28.0	31.7	35.0	37.9	40.5	40.1	39.5	38.8
Freezer	-	0.0	0.1	0.2	0.7	1.5	3.0	4.9	7.0	9.2	11.5	13.7	15.7	17.6	19.3	20.8	22.2	23.5	23.7	23.8	23.8
Dishwasher	-	-	0.3	1.0	1.8	2.2	2.1	1.9	1.6	1.2	1.0	0.7	0.5	0.3	0.2	0.1	0.1	0.0	(0.0)	(0.0)	(0.0)
Water Heat	-	6.1	18.2	70.2	76.7	75.8	76.4	75.1	71.4	65.9	60.5	55.1	50.3	46.2	42.8	40.2	38.0	36.2	34.8	33.6	32.6
Clothes Dryer	-	0.0	0.0	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1	2.2	2.4	2.5	2.6	2.7
Misc	-	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.3
Total	-	37.3	148.2	376.5	589.5	786.9	949.4	1,043.2	1,023.6	975.1	928.5	878.7	833.9	794.2	760.4	749.2	740.4	734.2	726.5	720.7	716.3

Figure 24. Commercial Sector Achievable Potential Scenarios (Electricity Sales)

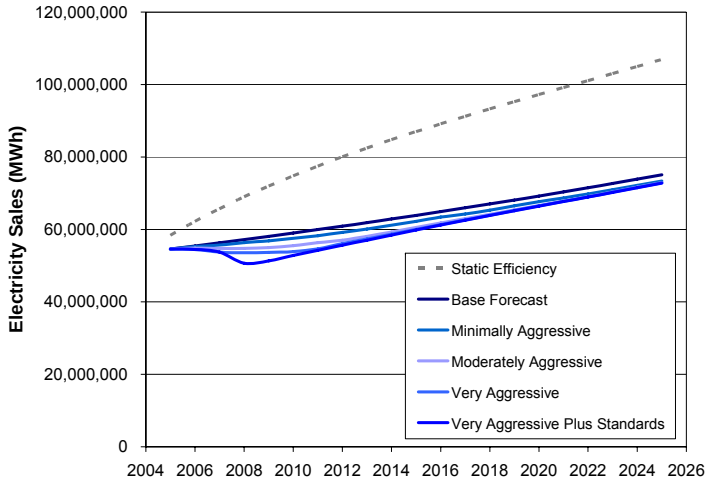

Figure 25. Commercial Sector Achievable Potential Scenarios (Peak Demand)

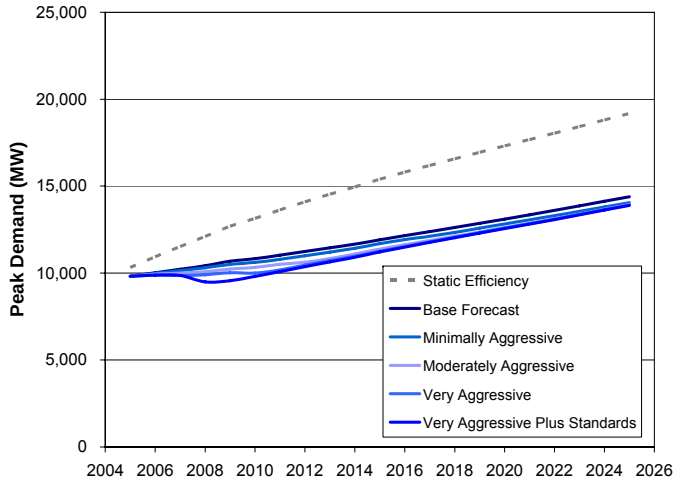

Figure 26. 2015 Commercial Sector Achievable Potential by End Use (Moderately Aggressive, Electricity Sales)

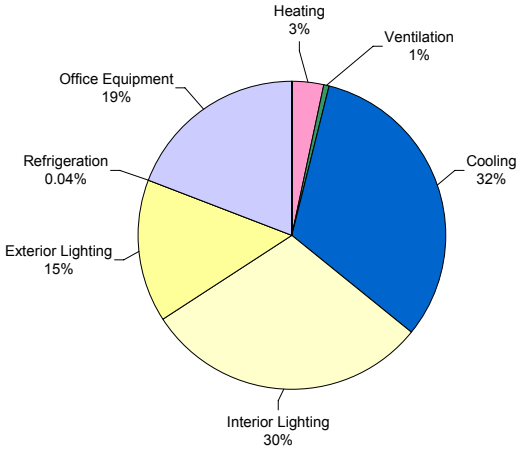

Figure 27. 2015 Commercial Sector Achievable Potential by End Use (Moderately Aggressive, Peak Demand)

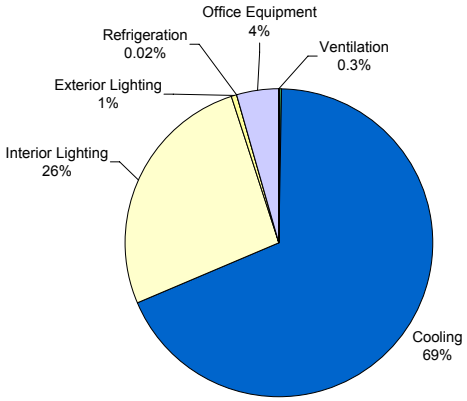

Figure 28. 2015 Commercial Sector Achievable Potential by Sub-sector (Moderately Aggressive, Electricity Sales)

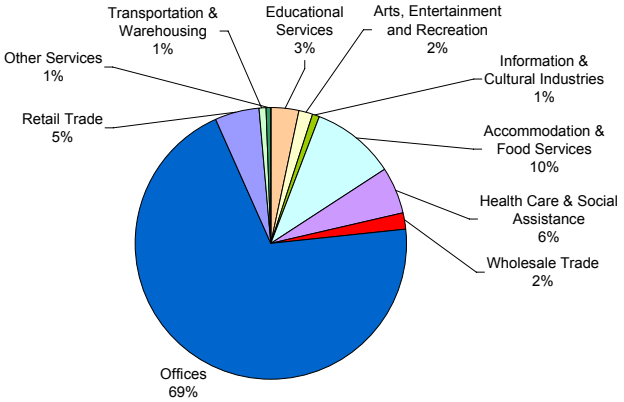

Figure 29. 2015 Commercial Sector Achievable Potential by Sub-sector (Moderately Aggressive, Peak Demand)

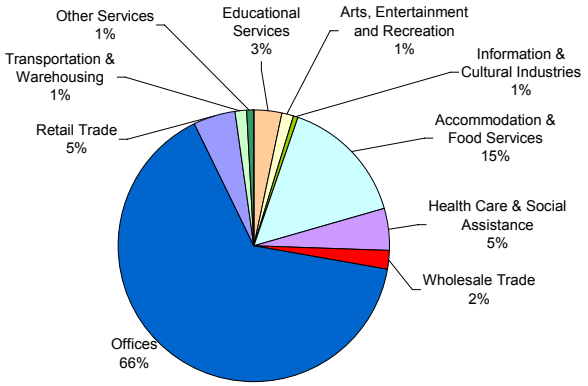

Table 12. Commercial Sector Results by End Use

Minimally Aggressive Scenario

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	3,967	11,842	22,999	36,195	49,683	61,527	70,043	74,226	73,951	69,899	63,227	55,192	46,860	38,978	31,977	36,161	31,380	27,982	25,706	24,284
Ventilation	-	12,791	25,216	31,584	31,640	27,686	22,298	17,210	13,177	23,437	19,749	17,435	15,932	14,908	14,172	13,616	-	-	-	-	-
Cooling	-	35,313	91,249	153,137	209,057	251,402	277,002	286,182	281,421	266,140	304,043	312,990	435,724	555,894	625,692	714,232	812,475	914,681	956,378	1,011,239	1,058,516
Interior Lighting	-	89,369	337,280	395,186	593,535	695,061	751,548	730,096	703,735	643,731	566,769	485,336	584,446	544,944	457,354	394,443	348,009	314,210	289,862	272,439	260,016
Exterior Lighting	-	18,719	50,875	92,994	169,198	209,192	247,841	265,535	288,105	296,932	293,158	279,597	312,382	284,600	252,358	221,221	238,697	207,600	180,593	157,535	138,162
Refrigeration	-	403	904	1,347	1,647	2,090	1,964	1,754	1,500	991	776	602	751	618	526	461	414	380	353	332	315
Office Equipment	-	18,038	54,457	107,113	170,986	238,501	300,757	349,468	378,955	387,366	376,612	351,170	316,462	277,499	238,171	201,088	252,752	241,576	239,349	244,490	254,953
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	178,600	571,822	804,361	1,212,257	1,473,615	1,662,937	1,720,288	1,741,119	1,692,549	1,631,006	1,510,357	1,720,889	1,725,324	1,627,251	1,577,039	1,688,508	1,709,827	1,694,516	1,711,741	1,736,245
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	0.8	1.6	1.9	1.9	1.7	1.3	1.1	0.8	1.6	1.5	1.4	1.3	1.2	1.1	1.1	-	-	-	-	-
Cooling	-	13.1	35.5	62.6	89.9	111.6	126.8	134.1	134.1	127.9	138.2	140.7	173.5	195.9	199.6	211.0	227.3	246.9	253.1	262.1	276.4
Interior Lighting	-	11.2	38.1	51.1	78.2	91.8	100.2	98.2	95.6	88.4	79.5	69.2	86.4	82.0	69.8	60.8	53.9	48.8	44.9	42.1	39.9
Exterior Lighting	-	0.1	0.3	0.6	1.0	1.3	1.5	1.6	1.7	1.8	1.7	1.6	1.8	1.6	1.4	1.2	1.3	1.1	1.0	0.9	0.8
Refrigeration	-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Equipment	-	0.7	2.2	4.2	6.5	8.8	10.7	12.0	12.5	12.2	11.4	10.2	8.9	7.5	6.2	5.2	9.0	11.9	15.2	19.0	22.9
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	26.0	77.8	120.5	177.7	215.3	240.7	247.1	244.9	231.9	232.4	223.2	271.8	288.3	278.3	279.3	291.6	308.7	314.3	324.1	340.1

Moderately Aggressive Scenario

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	12,925	39,421	74,956	109,869	134,119	143,247	139,430	127,739	124,974	108,232	93,398	80,510	69,411	59,868	51,721	44,904	39,358	34,975	31,593	29,029
Ventilation	-	37,817	69,051	77,235	67,998	78,757	54,537	39,075	29,407	23,437	19,749	17,435	15,932	14,908	14,172	13,616	-	-	-	-	-
Cooling	-	108,430	271,767	428,400	536,972	586,163	664,948	817,129	954,624	993,247	1,066,829	1,154,110	1,234,808	1,297,512	1,340,997	1,372,545	1,394,814	1,412,803	1,371,305	1,349,063	1,329,920
Interior Lighting	-	275,347	801,290	1,167,616	1,431,468	1,537,882	1,496,049	1,612,117	1,460,891	1,210,055	998,373	824,237	684,456	574,785	487,221	424,064	377,095	342,484	317,075	298,383	284,531
Exterior Lighting	-	58,362	158,928	315,320	418,888	495,046	531,293	569,801	544,989	549,839	499,447	449,885	401,958	356,412	313,895	274,936	239,859	208,851	181,928	158,951	139,655
Refrigeration	-	1,228	2,662	4,283	4,340	3,961	3,332	3,089	2,375	1,590	1,212	941	751	618	526	461	414	380	353	332	315
Office Equipment	-	58,774	181,367	349,555	520,479	647,066	705,785	703,459	661,486	689,277	634,420	591,047	557,419	529,031	501,197	472,042	442,822	415,864	392,811	374,232	359,964
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	552,884	1,524,486	2,417,365	3,090,014	3,482,994	3,599,191	3,884,099	3,781,512	3,592,419	3,328,262	3,131,053	2,975,835	2,842,678	2,717,876	2,609,385	2,499,908	2,419,740	2,298,447	2,212,554	2,143,413
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	2.4	4.3	4.7	4.2	4.6	3.3	2.4	1.9	1.6	1.5	1.4	1.3	1.2	1.1	1.1	-	-	-	-	-
Cooling	-	40.5	107.4	178.6	235.7	264.8	299.0	369.7	389.5	369.9	367.3	369.5	375.2	380.6	384.4	387.6	389.9	392.1	379.7	370.8	368.9
Interior Lighting	-	34.7	97.7	151.5	188.9	203.7	200.0	218.8	201.0	168.1	142.4	119.3	100.4	85.3	73.1	64.0	57.1	51.9	47.9	44.9	42.6
Exterior Lighting	-	0.4	1.0	2.0	2.6	3.1	3.3	3.5	3.3	3.2	2.9	2.6	2.3	2.0	1.8	1.5	1.3	1.2	1.0	0.9	0.8
Refrigeration	-	0.1	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Equipment	-	2.4	7.2	13.5	19.7	23.6	24.8	23.7	21.3	22.8	23.7	25.7	28.8	31.9	34.4	36.0	36.8	37.2	37.4	37.7	38.0
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	80.4	217.7	350.5	451.4	500.0	530.5	618.3	617.2	565.7	537.9	518.5	507.9	501.1	494.8	490.3	485.1	482.3	466.1	454.3	450.4

Commercial Sector Results by End Use *(continued)*

Very Aggressive Scenario

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	23,276	70,844	125,730	163,253	174,692	185,328	165,702	147,279	129,998	113,622	98,232	84,190	71,808	61,213	52,383	45,200	39,485	35,030	31,618	29,042
Ventilation	-	61,519	102,938	103,740	115,714	78,757	54,537	39,075	29,407	23,437	19,749	17,435	15,932	14,908	14,172	13,616	-	-	-	-	-
Cooling	-	183,207	436,789	636,385	851,860	1,081,797	1,273,896	1,312,132	1,379,610	1,437,179	1,467,629	1,475,065	1,470,388	1,462,428	1,456,284	1,456,767	1,461,253	1,469,854	1,424,042	1,400,126	1,380,849
Interior Lighting	-	467,631	1,311,291	1,699,008	1,916,867	2,279,487	2,125,267	1,762,239	1,473,272	1,222,989	1,011,598	837,418	697,288	587,044	498,776	434,856	387,116	351,755	325,635	306,279	291,810
Exterior Lighting	-	100,711	318,921	475,793	585,750	680,571	716,397	650,790	601,397	551,220	501,052	451,711	403,998	358,659	316,339	277,569	242,671	211,832	185,070	162,245	143,094
Refrigeration	-	2,063	4,241	5,805	5,446	5,247	4,028	3,089	2,375	1,590	1,212	941	751	618	526	461	414	380	353	332	315
Office Equipment	-	105,842	326,076	587,022	775,098	845,617	938,496	880,839	834,757	793,544	747,217	693,141	635,936	580,771	530,628	486,774	449,555	418,821	394,127	374,849	360,273
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	944,249	2,571,100	3,633,483	4,413,989	5,146,167	5,297,949	4,813,866	4,468,097	4,159,957	3,862,079	3,573,942	3,308,484	3,076,238	2,877,939	2,722,426	2,586,208	2,492,127	2,364,257	2,275,449	2,205,383
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	3.9	6.4	6.4	7.1	4.6	3.3	2.4	1.9	1.6	1.5	1.4	1.3	1.2	1.1	1.1	-	-	-	-	-
Cooling	-	68.9	174.7	268.9	366.1	486.9	524.9	500.3	488.0	478.3	471.4	458.7	445.7	434.3	425.4	420.4	417.8	417.5	404.0	394.8	393.1
Interior Lighting	-	59.0	163.2	220.7	253.3	302.7	286.0	239.3	202.3	169.5	143.8	120.7	101.7	86.6	74.3	65.2	58.2	52.9	48.8	45.8	43.4
Exterior Lighting	-	0.6	2.0	3.0	3.7	4.2	4.4	4.0	3.6	3.3	2.9	2.6	2.3	2.0	1.8	1.6	1.4	1.2	1.1	0.9	0.8
Refrigeration	-	0.1	0.3	0.4	0.3	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Equipment	-	4.3	12.9	22.7	29.2	30.7	34.0	34.2	36.3	39.0	41.1	41.2	40.5	39.5	38.7	38.1	37.7	37.6	37.6	37.8	38.1
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	136.9	359.5	522.0	659.8	829.5	852.8	780.4	732.3	691.7	660.9	624.7	591.6	563.7	541.4	526.3	515.1	509.1	491.5	479.3	475.4

Very Aggressive Plus Standards

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	23,276	70,844	248,488	228,829	209,290	189,841	170,341	150,988	132,285	114,730	98,678	84,352	71,864	61,233	52,390	45,202	39,486	35,030	31,618	29,042
Ventilation	-	61,519	102,938	170,464	115,714	78,757	54,537	39,075	29,407	23,437	19,749	17,435	15,932	14,908	14,172	13,616	-	-	-	-	-
Cooling	-	183,207	436,789	1,218,034	1,571,329	1,552,039	1,582,684	1,616,508	1,624,972	1,609,025	1,581,070	1,551,520	1,526,183	1,507,553	1,496,283	1,494,572	1,498,395	1,507,123	1,461,888	1,438,710	1,420,279
Interior Lighting	-	467,631	1,311,291	2,804,049	2,906,058	2,509,666	2,142,873	1,781,931	1,494,575	1,245,480	1,034,991	861,554	722,084	612,464	524,812	461,516	414,418	379,727	354,308	333,434	317,687
Exterior Lighting	-	100,711	318,921	863,734	822,873	770,461	718,690	653,519	604,567	554,830	505,099	456,187	408,891	363,953	322,019	283,617	249,067	218,560	192,111	169,583	150,716
Refrigeration	-	2,063	4,241	8,814	6,810	5,247	4,028	3,089	2,375	1,590	1,212	941	751	618	526	461	414	380	353	332	315
Office Equipment	-	105,842	326,076	1,177,629	1,123,520	1,076,163	1,029,689	975,416	911,138	841,182	770,599	702,716	639,473	582,032	531,082	486,943	449,621	418,848	394,138	374,854	360,275
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	944,249	2,571,100	6,491,211	6,775,133	6,201,623	5,722,342	5,239,878	4,818,023	4,407,830	4,027,450	3,689,030	3,397,665	3,153,394	2,950,127	2,793,115	2,657,119	2,564,123	2,437,828	2,348,532	2,278,314
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	3.9	6.4	10.4	7.1	4.6	3.3	2.4	1.9	1.6	1.5	1.4	1.3	1.2	1.1	1.1	-	-	-	-	-
Cooling	-	68.9	174.7	506.1	674.1	626.6	599.0	576.6	554.0	528.9	508.9	487.3	469.2	455.2	445.1	439.7	437.2	437.2	424.1	415.4	414.2
Interior Lighting	-	59.0	163.2	365.8	387.5	334.4	288.2	241.9	205.1	172.5	147.0	124.0	105.2	90.2	78.1	69.1	62.2	57.1	53.2	50.0	47.6
Exterior Lighting	-	0.6	2.0	5.4	5.2	4.8	4.4	4.0	3.6	3.3	3.0	2.7	2.4	2.1	1.8	1.6	1.4	1.3	1.1	1.0	0.9
Refrigeration	-	0.1	0.3	0.5	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Office Equipment	-	4.3	12.9	46.7	46.6	47.4	48.9	49.4	48.4	46.4	44.6	42.7	41.0	39.7	38.7	38.1	37.7	37.6	37.6	37.8	38.1
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	136.9	359.5	934.9	1,120.9	1,018.1	944.1	874.6	813.2	752.8	705.1	658.1	619.2	588.4	565.0	549.7	538.6	533.1	516.1	504.2	500.8

Table 13. Commercial Sector Results by Sub-sector

Minimally Aggressive Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	6,329	16,386	27,999	43,561	51,984	57,945	58,526	58,738	56,873	55,798	52,165	57,790	57,574	54,231	52,284	55,030	55,132	52,406	51,086	49,993
Arts, Entertainment and Recreation	-	1,387	3,307	5,359	10,013	11,582	13,373	13,564	15,595	18,504	20,070	21,284	26,326	30,713	34,714	39,103	43,837	47,886	51,642	55,375	58,983
Information & Cultural Industries	-	2,104	5,299	8,781	12,015	14,908	16,518	17,240	19,340	19,087	17,950	17,067	19,783	18,700	13,884	12,648	11,849	11,003	10,296	9,755	9,330
Accommodation & Food Services	-	14,641	39,648	78,340	99,829	126,882	147,159	159,016	162,249	158,422	151,565	139,524	156,198	160,209	155,357	155,157	175,289	184,294	192,540	203,110	213,978
Health Care & Social Assistance	-	12,449	41,209	53,808	74,087	89,599	98,906	101,975	99,753	94,805	90,472	83,291	98,421	96,916	93,298	92,129	99,009	101,356	100,531	101,572	102,841
Wholesale Trade	-	8,103	23,639	30,207	50,812	52,766	52,511	45,429	42,510	38,167	33,954	29,319	30,142	27,834	25,434	24,199	25,582	25,967	25,900	26,099	26,350
Offices	-	109,000	367,820	502,317	776,888	964,214	1,108,310	1,165,908	1,193,696	1,171,786	1,142,244	1,065,946	1,226,154	1,239,135	1,168,106	1,127,447	1,203,260	1,212,032	1,191,639	1,196,366	1,206,906
Retail Trade	-	19,267	58,875	76,403	113,670	126,731	131,919	124,401	117,230	106,258	94,040	80,795	84,364	74,957	65,674	59,300	60,213	58,404	56,481	55,663	55,375
Transportation & Warehousing	-	3,660	9,757	14,436	21,178	23,176	23,593	21,795	19,887	17,236	14,359	11,548	11,194	8,996	7,021	5,630	5,065	4,349	3,830	3,484	3,256
Other Services	-	1,662	5,881	6,711	10,203	11,772	12,703	12,434	12,121	11,411	10,553	9,418	10,517	10,290	9,531	9,142	9,376	9,405	9,251	9,230	9,234
Total	-	178,600	571,822	804,361	1,212,257	1,473,615	1,662,937	1,720,288	1,741,119	1,692,549	1,631,006	1,510,357	1,720,889	1,725,324	1,627,251	1,577,039	1,688,508	1,709,827	1,694,516	1,711,741	1,736,245
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.8	2.2	3.8	5.7	6.8	7.5	7.6	7.4	7.0	7.8	8.2	9.5	9.9	9.9	10.3	10.9	11.6	11.3	11.3	11.6
Arts, Entertainment and Recreation	-	0.1	0.4	0.6	1.1	1.3	1.6	1.7	1.8	2.0	2.3	2.5	3.4	4.1	4.6	5.3	5.9	6.5	7.0	7.5	8.1
Information & Cultural Industries	-	0.2	0.5	0.8	1.1	1.4	1.5	1.6	1.8	1.8	1.7	1.6	2.0	2.0	1.5	1.4	1.3	1.3	1.3	1.2	1.3
Accommodation & Food Services	-	3.5	9.5	17.6	23.8	29.6	33.6	35.4	35.3	33.5	32.5	30.3	38.5	42.4	41.6	42.7	45.9	49.7	53.0	56.7	60.8
Health Care & Social Assistance	-	1.4	4.4	6.4	8.9	10.7	11.8	12.1	11.7	10.9	11.1	10.8	13.4	14.0	13.7	14.0	14.7	15.7	15.9	16.3	17.1
Wholesale Trade	-	1.2	3.4	5.0	7.8	8.3	8.4	7.4	6.8	5.9	5.5	5.0	5.5	5.4	5.2	5.2	5.5	5.9	6.2	6.4	6.7
Offices	-	14.6	46.4	69.5	105.4	130.5	149.0	155.9	157.0	150.8	153.4	149.0	181.9	193.5	186.0	185.2	191.7	201.2	202.4	206.8	215.9
Retail Trade	-	3.1	8.5	12.5	17.8	19.6	20.0	18.4	16.6	14.3	12.8	11.2	12.5	11.9	11.0	10.7	11.0	11.6	11.9	12.4	12.9
Transportation & Warehousing	-	0.7	1.7	3.0	4.3	4.8	5.0	4.6	4.2	3.6	3.1	2.6	2.8	2.6	2.3	2.2	2.2	2.3	2.4	2.5	2.6
Other Services	-	0.3	0.8	1.2	1.8	2.2	2.4	2.4	2.3	2.2	2.1	2.0	2.4	2.6	2.5	2.5	2.6	2.8	2.8	2.9	3.1
Total	-	26.0	77.8	120.5	177.7	215.3	240.7	247.1	244.9	231.9	232.4	223.2	271.8	288.3	278.3	279.3	291.6	308.7	314.3	324.1	340.1

Moderately Aggressive Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	19,526	49,603	85,472	108,164	121,272	126,358	133,304	128,412	120,395	110,095	101,863	94,980	89,000	83,744	79,237	74,771	71,770	66,105	62,113	58,742
Arts, Entertainment and Recreation	-	4,181	9,736	17,983	22,233	27,661	30,466	34,970	40,602	47,132	51,864	56,484	60,873	64,930	68,602	72,390	74,467	77,507	80,004	82,280	84,295
Information & Cultural Industries	-	6,455	15,787	25,197	31,028	36,133	36,036	38,548	35,515	32,284	28,870	25,997	23,572	21,517	16,513	15,073	13,071	12,090	11,238	10,555	10,002
Accommodation & Food Services	-	45,924	131,274	214,719	273,865	313,762	326,168	355,298	354,354	349,674	334,775	327,216	323,304	319,771	314,859	308,925	301,740	295,519	287,117	281,057	276,481
Health Care & Social Assistance	-	38,693	106,236	154,245	193,263	210,433	210,499	225,352	211,165	200,105	186,175	176,488	169,218	163,030	157,282	152,052	146,162	142,192	134,911	129,778	125,535
Wholesale Trade	-	24,728	61,436	98,758	109,570	110,250	102,548	95,492	84,580	75,745	66,772	60,227	55,239	51,157	47,619	44,574	41,879	39,696	37,079	34,905	33,071
Offices	-	337,604	955,037	1,525,513	2,005,299	2,303,435	2,428,350	2,670,191	2,638,069	2,513,636	2,332,222	2,192,934	2,080,434	1,982,558	1,893,137	1,813,168	1,734,437	1,675,799	1,585,223	1,521,785	1,470,630
Retail Trade	-	59,406	153,659	231,637	271,697	282,204	265,734	258,824	225,691	199,438	172,039	151,083	134,738	121,487	110,337	100,930	92,580	86,067	79,337	73,928	69,512
Transportation & Warehousing	-	11,272	27,717	43,492	50,089	50,878	46,335	44,323	36,847	30,184	24,073	19,269	15,499	12,535	10,206	8,405	7,084	6,026	5,171	4,521	4,032
Other Services	-	5,097	14,000	20,349	24,808	26,967	26,697	27,797	26,276	23,827	21,375	19,493	17,979	16,694	15,575	14,631	13,717	13,075	12,261	11,633	11,114
Total	-	552,884	1,524,486	2,417,365	3,090,014	3,482,994	3,599,191	3,884,099	3,781,512	3,592,419	3,328,262	3,131,053	2,975,835	2,842,678	2,717,876	2,609,385	2,499,908	2,419,740	2,298,447	2,212,554	2,143,413
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	2.6	6.6	11.1	14.1	15.5	17.6	20.5	20.0	18.6	18.0	17.6	17.5	17.4	17.3	17.2	17.1	17.1	16.0	15.2	14.8
Arts, Entertainment and Recreation	-	0.4	1.1	2.0	2.6	3.1	3.7	4.8	5.6	6.1	6.8	7.4	8.1	8.7	9.2	9.8	10.3	10.7	11.0	11.2	11.5
Information & Cultural Industries	-	0.6	1.4	2.3	2.9	3.3	3.3	3.8	3.7	3.3	3.0	2.8	2.6	2.4	1.9	1.8	1.7	1.6	1.6	1.5	1.5
Accommodation & Food Services	-	10.9	29.8	49.0	63.2	70.6	73.9	88.2	91.3	85.4	83.2	82.4	82.8	83.5	84.0	84.2	84.1	84.0	82.9	82.2	82.1
Health Care & Social Assistance	-	4.4	11.9	18.1	22.9	24.7	25.9	30.1	29.3	26.9	25.9	25.2	24.9	24.8	24.7	24.6	24.5	24.4	23.5	22.9	22.7
Wholesale Trade	-	3.8	9.5	15.2	17.5	17.5	16.9	17.4	15.8	13.7	12.6	11.7	11.2	10.8	10.5	10.3	10.0	9.9	9.4	9.1	8.9
Offices	-	45.2	125.8	204.1	270.5	306.9	333.9	396.3	400.2	368.2	349.7	336.2	328.0	322.3	317.4	313.6	309.7	307.5	295.7	287.2	284.4
Retail Trade	-	9.5	24.0	36.5	42.7	42.7	40.2	40.9	36.0	30.4	27.1	24.5	22.8	21.7	20.8	20.1	19.4	19.0	18.1	17.5	17.0
Transportation & Warehousing	-	2.2	5.3	8.8	10.5	10.6	10.0	10.3	9.3	7.7	6.6	5.8	5.3	4.8	4.5	4.2	4.0	3.9	3.7	3.6	3.4
Other Services	-	0.9	2.3	3.6	4.6	5.0	5.3	6.1	6.1	5.5	5.2	4.9	4.8	4.7	4.6	4.5	4.4	4.4	4.2	4.1	4.0
Total	-	80.4	217.7	350.5	451.4	500.0	530.5	618.3	617.2	565.7	537.9	518.5	507.9	501.1	494.8	490.3	485.1	482.3	466.1	454.3	450.4

Commercial Sector Results by Sub-sector *(continued)*

Very Aggressive Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	33,227	87,755	127,253	157,214	180,382	183,324	164,044	149,922	136,852	124,450	112,977	102,843	94,271	87,262	81,726	76,731	73,494	67,751	63,746	60,396
Arts, Entertainment and Recreation	-	6,967	19,239	25,696	32,830	39,592	47,059	50,343	55,825	61,162	66,088	70,479	74,318	77,635	80,486	83,438	84,702	86,973	88,751	90,362	91,764
Information & Cultural Industries	-	10,917	25,452	36,996	44,186	49,849	47,248	41,902	37,315	33,096	29,657	26,674	24,110	21,930	16,834	15,337	13,303	12,308	11,453	10,772	10,225
Accommodation & Food Services	-	79,452	213,972	329,520	394,055	460,979	494,922	466,211	448,291	433,678	416,691	396,593	375,558	355,751	338,385	324,342	312,504	303,849	294,273	287,693	282,936
Health Care & Social Assistance	-	66,279	168,538	232,631	273,904	307,410	300,366	273,097	252,200	234,462	217,948	202,419	188,400	176,317	166,280	158,340	150,927	146,180	138,553	133,286	129,028
Wholesale Trade	-	41,681	116,301	138,541	148,434	152,185	139,015	114,554	100,639	89,099	78,961	69,975	62,225	55,759	50,509	46,397	43,109	40,621	37,859	35,617	33,753
Offices	-	576,905	1,603,894	2,311,832	2,888,139	3,454,361	3,629,653	3,322,294	3,095,752	2,887,792	2,682,577	2,482,028	2,296,107	2,132,683	1,994,927	1,884,272	1,788,343	1,721,036	1,626,678	1,561,871	1,510,662
Retail Trade	-	101,055	263,982	338,137	372,754	391,548	356,516	298,830	258,268	224,585	195,527	170,252	148,695	130,777	116,199	104,645	95,115	88,011	81,009	75,480	71,017
Transportation & Warehousing	-	19,145	48,632	62,964	67,469	70,361	60,994	48,706	39,515	31,922	25,658	20,540	16,426	13,172	10,639	8,709	7,314	6,214	5,339	4,677	4,183
Other Services	-	8,622	23,336	29,911	35,004	39,502	38,852	33,884	30,370	27,308	24,522	22,004	19,802	17,942	16,418	15,220	14,160	13,441	12,590	11,945	11,420
Total	-	944,249	2,571,100	3,633,483	4,413,989	5,146,167	5,297,949	4,813,866	4,468,097	4,159,957	3,862,079	3,573,942	3,308,484	3,076,238	2,877,939	2,722,426	2,586,208	2,492,127	2,364,257	2,275,449	2,205,383
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	4.4	11.1	16.3	22.3	28.0	27.7	25.6	24.3	23.1	22.2	21.1	20.2	19.4	18.7	18.4	18.1	18.0	16.9	16.0	15.7
Arts, Entertainment and Recreation	-	0.7	2.0	2.9	4.0	5.5	6.4	6.9	7.6	8.2	8.9	9.5	10.0	10.4	10.8	11.2	11.6	11.9	12.1	12.3	12.6
Information & Cultural Industries	-	0.9	2.3	3.3	4.1	4.9	4.8	4.3	3.9	3.5	3.2	3.0	2.7	2.6	2.0	1.9	1.8	1.7	1.6	1.6	1.6
Accommodation & Food Services	-	18.6	48.4	73.8	90.8	116.5	125.2	117.4	113.0	109.6	107.2	103.3	99.2	95.6	92.7	90.7	89.3	88.6	87.1	86.3	86.3
Health Care & Social Assistance	-	7.6	19.0	26.9	33.5	41.1	40.7	37.4	35.2	33.4	32.1	30.5	29.1	28.0	27.1	26.5	26.0	25.8	24.8	24.2	24.0
Wholesale Trade	-	6.4	16.9	21.6	24.5	27.3	25.3	21.4	19.0	17.2	15.8	14.4	13.3	12.3	11.5	11.0	10.6	10.3	9.9	9.5	9.3
Offices	-	76.8	206.7	306.0	400.7	517.5	541.6	499.1	469.9	444.3	424.0	400.4	378.8	360.5	346.0	335.9	328.4	324.4	311.9	303.2	300.6
Retail Trade	-	16.2	40.2	53.0	58.9	64.3	57.6	48.2	41.7	36.6	33.0	29.5	26.6	24.4	22.6	21.4	20.4	19.8	18.9	18.2	17.7
Transportation & Warehousing	-	3.7	9.2	12.8	14.3	16.1	14.8	12.3	10.5	9.1	8.0	6.9	6.1	5.4	4.9	4.5	4.3	4.1	3.9	3.7	3.6
Other Services	-	1.4	3.8	5.3	6.7	8.5	8.6	7.8	7.2	6.8	6.4	6.0	5.6	5.3	5.0	4.8	4.7	4.6	4.4	4.3	4.2
Total	-	136.9	359.5	522.0	659.8	829.5	852.8	780.4	732.3	691.7	660.9	624.7	591.6	563.7	541.4	526.3	515.1	509.1	491.5	479.3	475.4

Very Aggressive Plus Standards

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	33,227	87,755	224,963	235,717	213,562	194,624	174,776	158,192	142,364	127,963	115,389	104,755	95,990	88,929	83,402	78,444	75,256	69,572	65,624	62,334
Arts, Entertainment and Recreation	-	6,967	19,239	43,863	48,268	52,786	58,043	61,842	67,347	72,350	76,782	80,644	83,969	86,808	89,214	91,757	92,644	94,569	96,029	95,094	94,179
Information & Cultural Industries	-	10,917	25,452	64,173	61,112	54,061	47,981	42,687	38,044	33,726	30,208	27,184	24,611	22,441	17,368	15,899	13,896	12,933	12,112	11,465	10,953
Accommodation & Food Services	-	79,452	213,972	609,125	629,318	589,870	560,433	533,118	503,334	471,588	440,225	411,126	385,305	363,154	344,696	330,179	318,173	309,503	299,989	293,505	288,864
Health Care & Social Assistance	-	66,279	168,538	415,377	395,899	356,548	325,012	297,547	271,890	247,997	226,559	208,009	192,398	179,546	169,163	161,090	153,647	148,923	141,349	136,144	131,954
Wholesale Trade	-	41,681	116,301	228,595	203,591	173,295	149,148	124,480	108,472	94,307	82,109	71,884	63,492	56,717	51,320	47,140	43,823	41,323	38,559	36,318	34,456
Offices	-	576,905	1,603,894	4,172,451	4,542,146	4,200,389	3,907,100	3,600,578	3,323,797	3,048,897	2,789,877	2,556,824	2,354,477	2,183,781	2,043,406	1,932,413	1,837,273	1,771,317	1,678,625	1,615,593	1,566,238
Retail Trade	-	101,055	263,982	575,875	513,784	438,357	376,135	318,261	273,783	235,005	201,907	174,238	151,486	133,023	118,210	106,564	97,005	89,903	82,918	77,409	72,968
Transportation & Warehousing	-	19,145	48,632	104,950	92,453	76,148	62,416	50,133	40,704	32,802	26,290	21,017	16,817	13,520	10,967	9,029	7,629	6,529	5,653	4,991	4,495
Other Services	-	8,622	23,336	51,840	52,845	46,608	41,450	36,456	32,460	28,794	25,530	22,716	20,353	18,415	16,855	15,644	14,583	13,868	13,024	12,388	11,872
Total	-	944,249	2,571,100	6,491,211	6,775,133	6,201,623	5,722,342	5,239,878	4,818,023	4,407,830	4,027,450	3,689,030	3,397,665	3,153,394	2,950,127	2,793,115	2,657,119	2,564,123	2,437,828	2,348,532	2,278,314
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	4.4	11.1	29.3	35.9	32.7	30.5	28.4	26.6	24.8	23.4	22.0	20.9	20.0	19.4	19.0	18.7	18.6	17.5	16.7	16.4
Arts, Entertainment and Recreation	-	0.7	2.0	5.1	7.0	7.4	8.0	8.6	9.2	9.8	10.3	10.8	11.2	11.6	11.9	12.3	12.6	12.9	13.1	13.0	13.0
Information & Cultural Industries	-	0.9	2.3	5.7	6.2	5.5	5.0	4.5	4.1	3.6	3.4	3.1	2.8	2.6	2.1	2.0	1.9	1.8	1.7	1.7	1.7
Accommodation & Food Services	-	18.6	48.4	135.5	164.9	152.2	144.0	136.8	129.6	122.0	115.8	109.4	104.0	99.8	96.5	94.4	93.0	92.3	90.9	90.2	90.3
Health Care & Social Assistance	-	7.6	19.0	48.3	54.4	49.0	45.2	42.0	39.1	36.3	34.2	32.1	30.4	29.1	28.1	27.5	27.0	26.8	25.9	25.3	25.1
Wholesale Trade	-	6.4	16.9	36.3	37.5	31.9	27.8	23.9	21.1	18.7	16.9	15.2	13.8	12.7	11.9	11.4	11.0	10.7	10.2	9.9	9.6
Offices	-	76.8	206.7	553.9	693.9	637.6	596.0	555.4	518.4	481.1	451.0	421.1	396.2	376.3	361.3	351.2	343.9	340.3	328.3	320.2	318.1
Retail Trade	-	16.2	40.2	89.4	87.2	72.9	62.2	52.9	45.6	39.4	34.9	30.8	27.6	25.2	23.4	22.1	21.1	20.5	19.6	18.9	18.4
Transportation & Warehousing	-	3.7	9.2	21.8	22.2	18.6	15.9	13.4	11.5	9.8	8.5	7.3	6.4	5.7	5.1	4.7	4.5	4.3	4.1	3.9	3.8
Other Services	-	1.4	3.8	9.6	11.7	10.4	9.5	8.7	8.0	7.4	6.8	6.3	5.9	5.5	5.3	5.1	4.9	4.8	4.7	4.5	4.4
Total	-	136.9	359.5	934.9	1,120.9	1,018.1	944.1	874.6	813.2	752.8	705.1	658.1	619.2	588.4	565.0	549.7	538.6	533.1	516.1	504.2	500.8

Figure 30. Industrial Sector Achievable Potential Scenarios (Electricity Sales)

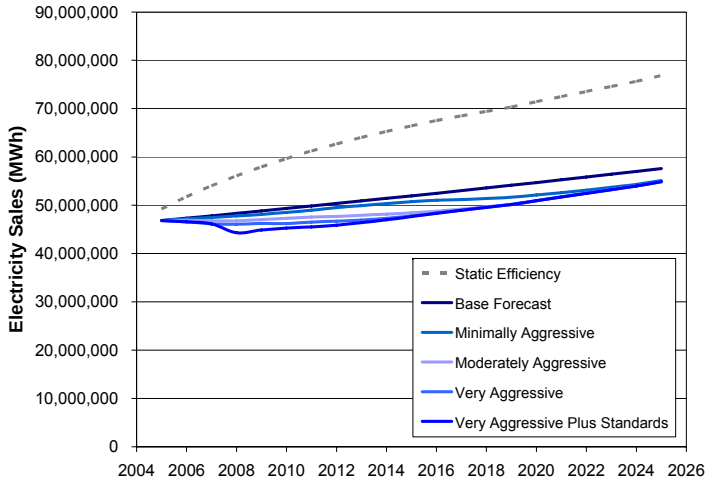

Figure 31. Industrial Sector Achievable Potential Scenarios (Peak Demand)

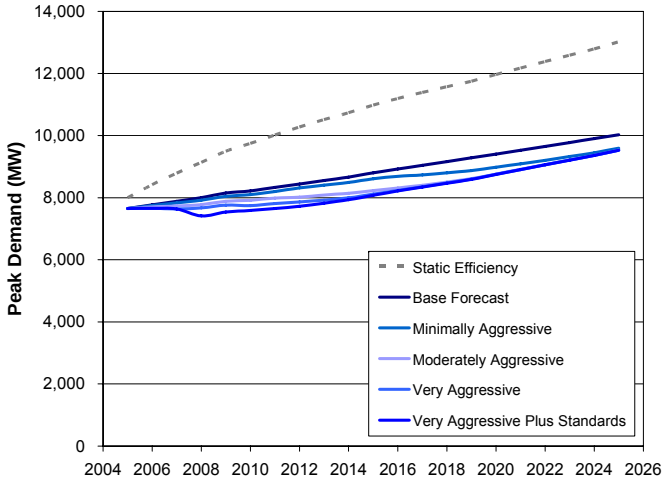

Figure 32. 2015 Industrial Sector Achievable Potential by End Use (Moderately Aggressive, Electricity Sales)

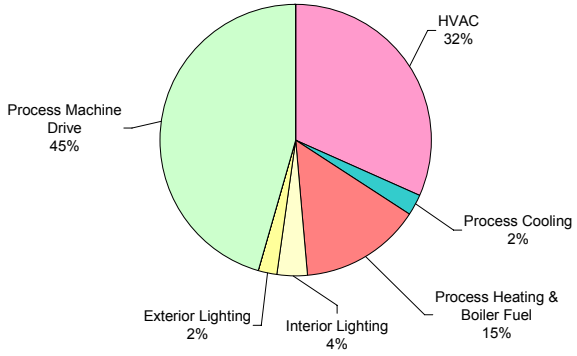

Figure 33. 2015 Industrial Sector Achievable Potential by End Use (Moderately Aggressive, Peak Demand)

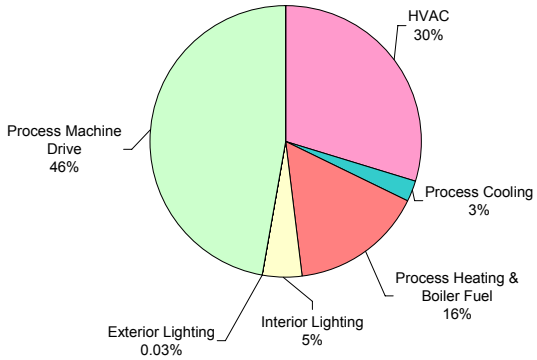

Figure 34. 2015 Industrial Sector Achievable Potential by Sub-sector (Moderately Aggressive, Electricity Sales)

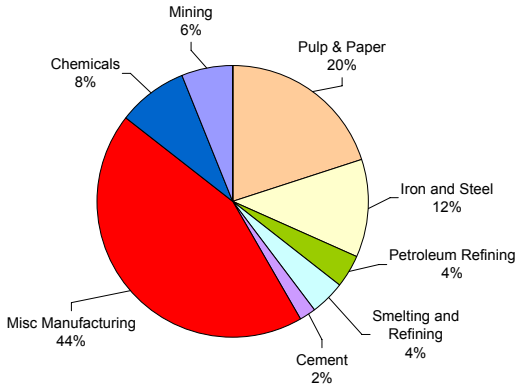

Figure 35. 2015 Industrial Sector Achievable Potential by Sub-sector (Moderately Aggressive, Peak Demand)

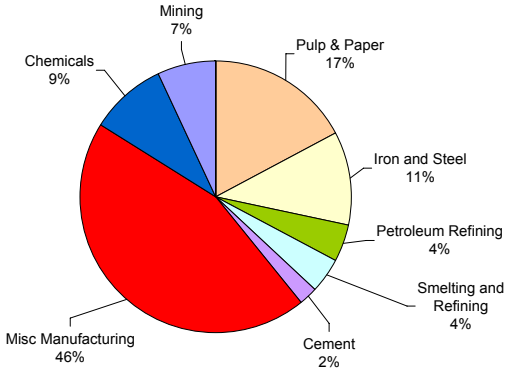

Table 14. Industrial Sector Results by End Use

Minimally Aggressive Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	29,643	74,128	120,267	158,298	182,729	192,096	187,952	173,594	163,513	148,089	274,645	387,878	514,611	656,488	806,332	947,297	1,083,326	1,201,349	1,299,439	1,242,377
Process Cooling	-	8,863	22,604	36,863	47,958	53,747	53,911	49,585	42,597	34,730	27,275	20,932	32,101	34,824	39,864	46,452	53,815	61,220	68,042	73,844	78,429
Process Heating & Boiler Fuel	-	53,615	141,253	238,802	323,328	378,672	398,551	386,004	350,001	301,247	249,024	199,741	272,314	240,123	223,110	217,823	220,744	228,530	238,292	247,855	255,910
Interior Lighting	-	15,519	38,858	63,085	96,490	105,701	143,381	129,176	118,572	105,014	90,651	43,183	49,408	41,262	33,167	27,263	22,718	19,202	16,437	14,270	13,156
Exterior Lighting	-	3,023	8,241	15,208	28,193	34,763	41,183	44,574	48,189	49,382	48,433	45,740	42,691	38,178	32,309	26,702	29,029	24,328	20,892	18,436	15,453
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	34,633	64,077	75,002	69,940	56,823	42,508	30,647	228,217	420,563	635,020	861,687	1,088,853	1,304,012	1,495,815	1,443,491	1,379,107	1,283,655	1,164,786	1,031,797	893,648
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	145,295	349,162	549,226	724,206	812,435	871,630	827,939	961,170	1,074,448	1,198,492	1,445,928	1,873,244	2,173,011	2,480,753	2,568,064	2,652,710	2,700,261	2,709,798	2,685,641	2,498,974
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	2.8	7.1	11.8	16.3	19.5	21.3	21.7	20.8	20.5	19.7	38.7	57.9	76.6	98.5	122.7	146.4	170.6	193.6	214.5	213.9
Process Cooling	-	1.6	4.0	6.5	8.6	9.6	9.7	9.0	7.9	6.5	5.3	4.2	6.5	7.0	7.9	9.1	10.4	11.8	13.0	14.1	14.9
Process Heating & Boiler Fuel	-	8.7	22.9	38.9	53.3	62.5	66.1	64.5	58.9	51.2	43.2	35.4	49.8	44.3	41.3	40.3	40.6	41.8	43.3	44.9	46.1
Interior Lighting	-	2.6	6.7	11.1	17.5	19.4	26.0	24.0	22.7	20.5	18.4	9.8	11.7	10.3	8.4	7.0	5.9	5.0	4.3	3.8	3.4
Exterior Lighting	-	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	5.6	10.4	12.4	11.9	9.7	7.4	5.5	39.4	71.4	108.4	146.5	185.0	221.7	254.8	245.4	235.1	219.4	199.7	177.5	154.3
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	21.2	51.1	80.8	107.6	120.8	130.6	124.8	149.7	170.3	195.2	234.7	311.0	360.1	411.0	424.5	438.4	448.7	454.1	454.9	432.9

Moderately Aggressive Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	91,169	221,199	336,682	404,429	432,096	584,842	671,456	790,134	954,351	1,123,331	1,269,665	1,375,119	1,440,921	1,478,865	1,501,325	1,506,080	1,511,030	1,515,672	1,520,927	1,399,157
Process Cooling	-	27,686	68,450	102,926	118,575	115,224	100,253	104,025	90,223	83,753	82,749	84,463	86,354	87,178	87,016	86,453	85,940	85,655	85,611	85,764	86,064
Process Heating & Boiler Fuel	-	167,486	428,259	669,189	805,426	822,010	754,435	822,092	691,595	591,064	516,663	461,384	417,894	381,681	351,483	327,381	309,179	296,092	287,058	281,056	277,244
Interior Lighting	-	47,324	114,395	187,914	247,595	245,923	226,230	220,217	186,939	152,633	124,290	67,653	52,432	41,262	33,167	27,263	22,718	19,202	16,437	14,270	13,156
Exterior Lighting	-	9,490	26,298	53,911	72,730	86,675	92,640	91,927	88,023	88,722	79,148	69,972	60,834	51,773	43,187	35,564	29,483	24,804	21,394	18,969	16,011
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	102,051	174,307	181,564	148,289	325,768	511,562	780,084	1,090,507	1,384,993	1,614,332	1,763,261	1,848,399	1,896,180	1,926,505	1,741,223	1,574,444	1,406,197	1,239,336	1,076,710	921,119
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	445,205	1,032,908	1,532,186	1,797,043	2,027,696	2,269,962	2,689,800	2,937,422	3,255,516	3,540,513	3,716,398	3,841,032	3,898,995	3,920,223	3,719,210	3,527,844	3,342,980	3,165,507	2,997,697	2,712,751
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	8.5	21.1	33.5	42.5	47.7	72.8	94.9	114.0	140.2	170.7	199.4	223.6	242.0	255.1	264.4	269.3	273.2	276.2	278.8	263.5
Process Cooling	-	4.8	12.0	18.2	21.3	20.7	18.1	19.1	16.8	15.6	15.8	16.1	16.4	16.6	16.6	16.5	16.4	16.3	16.3	16.3	16.4
Process Heating & Boiler Fuel	-	27.0	69.5	109.2	132.9	135.9	125.4	138.2	117.4	101.0	90.5	81.5	74.3	68.2	63.0	58.9	55.7	53.4	51.7	50.6	49.9
Interior Lighting	-	8.1	19.9	33.4	44.6	45.1	42.6	43.1	38.1	31.6	26.7	16.0	12.8	10.3	8.4	7.0	5.9	5.0	4.3	3.8	3.4
Exterior Lighting	-	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	16.5	28.4	30.0	25.3	54.8	86.0	130.9	183.0	232.4	272.7	298.5	313.8	322.8	328.8	297.0	269.2	241.1	213.1	185.7	159.5
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	64.9	150.9	224.4	266.7	304.4	345.1	426.4	469.4	521.0	576.5	611.6	641.0	659.9	672.0	643.8	616.7	589.2	561.9	535.5	492.9

Industrial Sector Results by End Use *(continued)*

Very Aggressive Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	154,450	357,454	502,080	563,316	711,324	809,490	971,426	1,170,780	1,337,872	1,438,322	1,484,932	1,502,977	1,509,988	1,514,548	1,520,093	1,516,920	1,518,337	1,521,465	1,526,103	1,404,375
Process Cooling	-	47,587	111,215	150,464	154,203	166,343	142,578	128,868	121,413	115,200	108,255	101,445	95,831	91,724	88,959	87,231	86,248	85,783	85,669	85,793	86,080
Process Heating & Boiler Fuel	-	287,879	696,523	980,915	1,052,318	1,197,476	1,024,483	885,012	771,786	673,220	584,410	507,279	443,997	394,475	357,090	329,687	310,118	296,490	287,240	281,147	277,293
Interior Lighting	-	79,606	202,625	295,521	306,398	327,539	283,369	227,480	186,939	152,633	124,290	67,653	52,432	41,262	33,167	27,263	22,718	19,202	16,437	14,270	13,156
Exterior Lighting	-	16,517	54,775	83,693	104,818	115,441	124,851	110,494	99,328	89,015	79,458	70,297	61,171	52,120	43,542	35,925	29,852	25,182	21,783	19,370	16,422
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	165,484	258,577	242,551	413,506	610,359	949,622	1,322,871	1,604,514	1,760,457	1,833,771	1,870,483	1,894,396	1,914,514	1,933,742	1,744,570	1,576,169	1,407,158	1,239,894	1,077,042	921,318
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	751,523	1,681,169	2,255,224	2,594,558	3,128,481	3,334,392	3,646,150	3,954,761	4,128,397	4,168,506	4,102,089	4,050,804	4,004,082	3,971,048	3,744,769	3,542,025	3,352,152	3,172,489	3,003,726	2,718,644
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	14.3	34.2	50.4	60.7	85.9	111.9	138.1	172.2	204.8	230.7	247.3	257.7	264.4	269.1	273.0	274.6	276.5	278.4	280.4	264.9
Process Cooling	-	8.3	19.6	26.6	27.7	29.9	25.9	23.6	22.4	21.3	20.4	19.2	18.2	17.4	16.9	16.6	16.4	16.3	16.3	16.3	16.4
Process Heating & Boiler Fuel	-	46.5	113.0	160.1	173.8	198.2	170.8	148.6	130.7	114.7	101.8	89.2	78.7	70.4	64.0	59.3	55.9	53.4	51.8	50.7	49.9
Interior Lighting	-	13.6	35.3	51.9	56.0	61.5	55.5	45.4	38.1	31.6	26.7	16.0	12.8	10.3	8.4	7.0	5.9	5.0	4.3	3.8	3.4
Exterior Lighting	-	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	26.7	42.1	40.1	70.8	101.9	158.7	221.2	268.8	295.4	309.9	316.9	321.8	326.0	330.1	297.6	269.6	241.3	213.2	185.8	159.5
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	109.4	244.3	329.3	389.2	477.7	523.0	577.1	632.4	667.9	689.7	688.8	689.3	688.7	688.8	653.7	622.5	592.8	564.3	537.2	494.3

Very Aggressive Plus Standards

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	154,450	357,454	958,749	1,041,175	1,146,763	1,303,537	1,437,952	1,513,212	1,539,974	1,542,063	1,536,077	1,530,025	1,526,913	1,527,459	1,531,520	1,527,888	1,529,255	1,532,498	1,537,317	1,416,127
Process Cooling	-	47,587	111,215	252,390	215,972	189,582	170,182	153,363	137,376	123,061	111,386	102,540	96,191	91,841	88,998	87,244	86,253	85,785	85,670	85,793	86,080
Process Heating & Boiler Fuel	-	287,879	696,523	1,652,237	1,439,081	1,254,119	1,092,982	946,977	812,998	693,973	592,892	510,334	445,036	394,824	357,210	329,729	310,134	296,496	287,243	281,148	277,293
Interior Lighting	-	79,606	202,625	440,714	404,884	340,452	283,883	228,101	187,658	153,438	125,172	68,604	53,448	42,339	34,302	28,455	23,962	20,495	17,777	15,655	14,588
Exterior Lighting	-	16,517	54,775	156,492	151,969	138,507	125,243	110,898	99,745	89,443	79,896	70,745	61,628	52,583	44,010	36,398	30,329	25,665	22,273	19,869	16,927
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	165,484	258,577	555,602	693,066	991,758	1,338,674	1,604,568	1,751,814	1,820,505	1,854,738	1,877,264	1,896,542	1,915,203	1,933,973	1,744,659	1,576,206	1,407,174	1,239,902	1,077,046	921,319
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	751,523	1,681,169	4,016,183	3,946,147	4,061,182	4,314,501	4,481,859	4,502,803	4,420,393	4,306,147	4,165,564	4,082,869	4,023,702	3,985,951	3,758,005	3,554,772	3,364,871	3,185,363	3,016,828	2,732,334
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	14.3	34.2	102.2	138.8	157.9	187.3	216.1	237.8	251.3	260.4	265.3	268.5	271.1	273.5	276.1	277.1	278.7	280.4	282.3	266.8
Process Cooling	-	8.3	19.6	44.9	39.1	34.1	30.9	28.0	25.3	22.7	21.0	19.4	18.3	17.5	16.9	16.6	16.4	16.3	16.3	16.3	16.4
Process Heating & Boiler Fuel	-	46.5	113.0	270.5	239.1	207.5	182.1	158.9	137.5	118.1	103.2	89.7	78.9	70.4	64.0	59.3	55.9	53.4	51.8	50.7	49.9
Interior Lighting	-	13.6	35.3	78.9	77.3	65.4	55.6	45.6	38.2	31.8	26.9	16.2	13.0	10.5	8.6	7.2	6.1	5.3	4.6	4.1	3.7
Exterior Lighting	-	0.0	0.1	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	26.7	42.1	92.2	117.0	165.0	223.2	268.0	293.4	305.4	313.4	318.1	322.2	326.2	330.2	297.6	269.6	241.3	213.2	185.8	159.5
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	109.4	244.3	589.0	611.6	630.3	679.3	716.8	732.5	729.6	725.2	708.9	701.0	695.9	693.5	657.1	625.3	595.2	566.6	539.4	496.5

Table 15. Industrial Sector Results by Sub-sector

Minimally Aggressive Scenario

Industrial Electric by Industry Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	20,005	42,751	60,105	72,259	74,845	76,741	69,998	134,366	195,859	264,147	343,292	435,975	517,164	592,162	583,873	574,384	552,894	522,583	486,088	436,239
Iron and Steel	-	27,628	69,922	114,723	153,415	176,688	187,524	180,126	182,012	178,054	174,334	175,309	229,653	239,922	254,744	252,795	253,544	252,544	249,775	244,998	233,390
Petroleum Refining	-	3,774	7,858	10,716	12,354	12,407	12,208	10,871	24,649	37,893	52,669	69,151	87,802	104,521	119,824	117,426	114,264	108,713	101,289	92,623	82,137
Smelting and Refining	-	10,082	25,521	41,882	56,017	64,530	68,471	65,786	66,491	65,054	63,698	64,076	83,930	87,687	93,110	92,401	92,602	92,281	91,276	89,536	85,298
Cement	-	2,368	5,300	7,811	9,627	10,370	10,548	9,822	15,762	21,281	27,451	34,382	43,842	50,991	57,667	56,330	54,753	52,147	48,723	44,745	39,991
Misc Manufacturing	-	62,488	154,038	247,580	335,548	380,641	418,505	400,028	414,226	423,023	429,866	529,377	696,506	826,997	968,865	1,068,639	1,165,617	1,250,056	1,316,447	1,364,508	1,289,833
Chemicals	-	9,665	21,592	31,711	39,422	42,088	43,684	40,269	62,326	83,102	106,304	135,155	172,832	204,479	234,493	234,380	233,145	227,554	218,271	206,262	187,016
Mining	-	9,283	22,180	34,700	45,564	50,866	53,949	51,039	61,338	70,182	80,021	95,185	122,703	141,250	159,886	162,221	164,402	164,072	161,434	156,880	145,070
Total	-	145,295	349,162	549,226	724,206	812,435	871,630	827,939	961,170	1,074,448	1,198,492	1,445,928	1,873,244	2,173,011	2,480,753	2,568,064	2,652,710	2,700,261	2,709,798	2,685,641	2,498,974
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pulp & Paper	-	2.6	5.5	7.7	9.2	9.4	9.6	8.8	18.4	27.3	37.6	48.8	62.4	74.1	84.9	83.4	81.8	78.6	74.1	68.8	61.9
Iron and Steel	-	4.0	10.3	17.0	22.9	26.4	28.2	27.2	27.8	27.4	27.3	27.5	36.8	38.4	40.6	40.1	40.1	40.0	39.6	39.0	37.5
Petroleum Refining	-	0.6	1.3	1.8	2.1	2.1	2.1	1.8	4.5	7.0	9.8	12.9	16.4	19.6	22.5	21.9	21.4	20.4	19.0	17.5	15.6
Smelting and Refining	-	1.5	3.8	6.2	8.4	9.7	10.3	9.9	10.2	10.0	10.0	10.0	13.5	14.0	14.8	14.7	14.7	14.6	14.5	14.3	13.7
Cement	-	0.4	0.9	1.4	1.7	1.8	1.9	1.7	2.9	3.9	5.1	6.4	8.3	9.6	10.9	10.6	10.3	9.8	9.2	8.5	7.6
Misc Manufacturing	-	8.9	22.1	35.8	49.2	56.0	62.5	60.1	64.5	67.5	71.4	87.1	119.0	140.6	164.5	180.8	197.3	213.4	227.6	239.6	234.1
Chemicals	-	1.6	3.6	5.2	6.5	6.9	7.2	6.6	10.9	14.9	19.5	24.8	32.0	37.9	43.4	43.2	43.0	42.0	40.4	38.3	35.2
Mining	-	1.5	3.7	5.7	7.6	8.5	9.0	8.5	10.6	12.4	14.5	17.2	22.6	26.0	29.4	29.6	30.0	29.9	29.6	28.9	27.2
Total	-	21.2	51.1	80.8	107.6	120.8	130.6	124.8	149.7	170.3	195.2	234.7	311.0	360.1	411.0	424.5	438.4	448.7	454.1	454.9	432.9

Moderately Aggressive Scenario

Industrial Electric by Industry Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	60,128	122,153	161,145	172,355	238,272	307,915	411,176	515,488	621,920	707,493	761,947	797,011	816,811	828,602	764,235	705,101	645,709	587,086	530,276	466,705
Iron and Steel	-	85,584	209,774	320,244	381,323	405,511	398,892	452,896	429,373	418,824	412,741	403,936	396,124	386,698	377,354	350,703	327,677	306,783	287,796	270,559	250,159
Petroleum Refining	-	11,312	22,297	28,267	29,050	42,466	56,240	77,173	99,173	120,941	138,287	149,323	155,993	159,613	161,745	147,958	135,455	122,924	110,556	98,555	85,965
Smelting and Refining	-	31,235	76,581	116,946	139,263	148,135	145,731	165,445	156,855	152,941	150,746	147,571	144,730	141,296	137,891	128,156	119,746	112,115	105,180	98,885	91,432
Cement	-	7,180	15,376	21,095	23,180	29,657	35,197	45,766	54,170	62,776	69,641	73,857	76,231	77,336	77,866	71,158	65,134	59,169	53,334	47,710	41,899
Misc Manufacturing	-	192,039	458,531	701,409	843,952	915,755	1,039,933	1,183,783	1,276,658	1,414,582	1,549,485	1,637,754	1,709,482	1,746,312	1,761,497	1,721,012	1,674,869	1,631,975	1,591,865	1,555,211	1,422,230
Chemicals	-	29,288	62,635	86,423	95,700	119,986	144,714	184,503	221,084	259,717	291,642	311,730	324,681	331,463	335,067	310,796	288,508	266,363	244,651	223,710	198,585
Mining	-	28,439	65,561	96,658	112,219	127,915	141,340	169,059	184,621	203,815	220,478	230,279	236,780	239,465	240,202	225,192	211,354	197,942	185,039	172,791	155,777
Total	-	445,205	1,032,908	1,532,186	1,797,043	2,027,696	2,269,962	2,689,800	2,937,422	3,255,516	3,540,513	3,716,398	3,841,032	3,898,995	3,920,223	3,719,210	3,527,844	3,342,980	3,165,507	2,997,697	2,712,751
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pulp & Paper	-	7.7	15.6	20.3	21.8	31.1	41.0	56.4	71.4	86.3	99.1	107.0	112.3	115.6	117.7	108.4	100.2	91.8	83.5	75.4	66.6
Iron and Steel	-	12.5	30.8	47.3	57.0	60.7	59.9	69.1	65.8	64.2	64.2	63.2	62.3	61.2	60.1	56.1	52.6	49.5	46.6	43.9	40.9
Petroleum Refining	-	1.9	3.8	4.8	4.9	7.4	10.0	14.0	18.1	22.1	25.5	27.7	29.1	29.9	30.5	27.9	25.7	23.4	21.1	18.9	16.6
Smelting and Refining	-	4.6	11.3	17.3	20.8	22.2	21.9	25.2	24.1	23.4	23.5	23.1	22.8	22.4	22.0	20.5	19.2	18.1	17.0	16.1	15.0
Cement	-	1.2	2.7	3.7	4.1	5.3	6.3	8.4	9.9	11.5	12.9	13.8	14.3	14.6	14.7	13.5	12.4	11.3	10.2	9.2	8.1
Misc Manufacturing	-	27.4	65.7	101.0	123.7	136.2	157.5	191.1	208.0	230.9	258.7	278.2	297.0	310.4	319.5	316.7	312.1	306.9	301.5	296.1	277.0
Chemicals	-	4.8	10.3	14.1	15.8	20.2	24.7	32.6	39.5	46.5	53.0	57.0	59.9	61.6	62.8	58.4	54.5	50.6	46.6	42.8	38.4
Mining	-	4.7	10.8	15.9	18.6	21.4	23.9	29.6	32.6	36.0	39.6	41.7	43.3	44.2	44.8	42.3	39.9	37.6	35.3	33.1	30.2
Total	-	64.9	150.9	224.4	266.7	304.4	345.1	426.4	469.4	521.0	576.5	611.6	641.0	659.9	672.0	643.8	616.7	589.2	561.9	535.5	492.9

Industrial Sector Results by Sub-sector *(continued)*

Very Aggressive Scenario

Industrial Electric by Industry

Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	99,555	193,319	231,128	303,160	395,818	508,247	634,813	737,670	796,354	821,919	827,129	830,796	833,347	836,454	768,083	707,091	646,861	587,859	530,876	467,243
Iron and Steel	-	145,956	340,694	469,873	518,406	602,258	563,576	540,919	523,691	500,460	471,795	440,194	415,533	396,031	381,555	352,610	328,604	307,298	288,134	270,818	250,390
Petroleum Refining	-	18,674	34,862	40,124	54,279	71,891	95,164	121,604	142,345	153,795	158,701	160,093	161,044	161,826	162,701	148,416	135,701	123,073	110,659	98,635	86,035
Smelting and Refining	-	53,273	124,403	171,614	189,387	219,996	205,669	197,508	191,253	182,793	172,340	160,829	151,827	144,709	139,428	128,854	120,086	112,305	105,305	98,981	91,517
Cement	-	11,992	24,377	30,305	37,807	47,854	56,395	66,700	74,651	78,524	79,556	79,168	78,758	78,452	78,348	71,385	65,253	59,239	53,382	47,746	41,930
Misc Manufacturing	-	325,183	756,656	1,045,314	1,173,799	1,400,492	1,465,553	1,581,355	1,727,361	1,829,554	1,868,804	1,844,643	1,826,784	1,807,123	1,791,908	1,736,784	1,683,975	1,638,144	1,596,767	1,559,586	1,426,610
Chemicals	-	48,894	100,222	125,368	153,992	192,797	229,335	273,542	310,394	330,865	338,580	338,179	337,941	337,636	337,875	312,166	289,253	266,832	244,994	223,993	198,851
Mining	-	47,996	106,637	141,497	163,729	197,375	210,452	229,709	247,397	256,051	256,811	251,853	248,121	244,958	242,780	226,470	212,062	198,401	185,388	173,091	156,068
Total	-	751,523	1,681,169	2,255,224	2,594,558	3,128,481	3,334,392	3,646,150	3,954,761	4,128,397	4,168,506	4,102,089	4,050,804	4,004,082	3,971,048	3,744,769	3,542,025	3,352,152	3,172,489	3,003,726	2,718,644

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	12.8	24.4	29.0	39.8	52.5	68.9	86.9	101.4	109.8	114.5	115.9	117.1	118.0	119.0	109.2	100.6	92.1	83.7	75.5	66.7
Iron and Steel	-	21.4	50.0	69.4	77.6	90.5	85.2	82.2	80.0	76.8	73.6	69.2	65.8	63.0	61.0	56.6	52.9	49.6	46.7	44.0	41.0
Petroleum Refining	-	3.2	5.9	6.7	9.5	12.7	17.1	22.0	26.0	28.2	29.4	29.8	30.2	30.5	30.8	28.1	25.7	23.4	21.1	18.9	16.6
Smelting and Refining	-	7.8	18.2	25.3	28.3	33.0	31.1	30.0	29.2	28.0	26.9	25.3	24.0	23.0	22.3	20.7	19.3	18.1	17.1	16.1	15.0
Cement	-	2.1	4.2	5.3	6.8	8.6	10.2	12.2	13.7	14.5	14.8	14.8	14.8	14.8	14.9	13.5	12.4	11.3	10.2	9.2	8.1
Misc Manufacturing	-	46.3	107.7	150.1	173.6	214.1	233.8	255.2	282.9	305.4	322.0	325.2	328.6	330.3	331.6	324.0	316.5	309.7	303.3	297.4	278.1
Chemicals	-	8.1	16.4	20.4	26.0	32.9	40.2	48.5	55.5	59.6	62.0	62.4	62.9	63.2	63.6	58.9	54.8	50.7	46.7	42.9	38.5
Mining	-	7.9	17.4	23.1	27.5	33.5	36.5	40.2	43.7	45.6	46.6	46.2	46.0	45.8	45.7	42.7	40.2	37.8	35.4	33.2	30.3
Total	-	109.4	244.3	329.3	389.2	477.7	523.0	577.1	632.4	667.9	689.7	688.8	689.3	688.7	688.8	653.7	622.5	592.8	564.3	537.2	494.3

Very Aggressive Plus Standards

Industrial Electric by Industry

Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	99,555	193,319	446,663	483,694	576,843	693,502	780,614	824,156	837,954	839,628	834,461	834,102	835,180	837,762	769,215	708,171	647,934	588,944	531,980	468,394
Iron and Steel	-	145,956	340,694	805,314	729,766	678,884	644,798	608,908	566,461	521,811	480,989	443,965	417,181	396,896	382,139	353,098	329,061	307,749	288,589	271,281	250,871
Petroleum Refining	-	18,674	34,862	78,725	86,179	105,695	129,775	147,892	157,153	160,475	161,364	161,132	161,489	162,061	162,863	148,555	135,832	123,203	110,790	98,768	86,173
Smelting and Refining	-	53,273	124,403	293,897	266,366	247,840	235,442	222,373	206,895	190,603	175,704	162,211	152,433	145,029	139,644	129,036	120,256	112,473	105,475	99,153	91,697
Cement	-	11,992	24,377	56,196	57,086	63,766	72,762	79,189	81,716	81,714	80,823	79,657	78,964	78,559	78,421	71,447	65,312	59,297	53,440	47,805	41,992
Misc Manufacturing	-	325,183	756,656	1,851,823	1,839,262	1,869,252	1,965,181	2,031,755	2,042,332	2,007,885	1,957,606	1,887,701	1,849,529	1,821,523	1,803,063	1,746,772	1,693,623	1,647,782	1,606,526	1,569,518	1,436,994
Chemicals	-	48,894	100,222	231,855	238,362	266,774	305,779	334,388	346,982	348,673	346,286	341,464	339,487	338,532	338,534	312,745	289,807	267,384	245,552	224,561	199,444
Mining	-	47,996	106,637	251,709	245,430	252,129	267,262	276,740	277,109	271,278	263,745	254,974	249,684	245,923	243,524	227,138	212,710	199,049	186,046	173,762	156,768
Total	-	751,523	1,681,169	4,016,183	3,946,147	4,061,182	4,314,501	4,481,859	4,502,803	4,420,393	4,306,147	4,165,564	4,082,869	4,023,702	3,985,951	3,758,005	3,554,772	3,364,871	3,185,363	3,016,828	2,732,334

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	12.8	24.4	56.5	64.1	76.6	93.3	106.1	113.1	115.8	117.4	117.3	117.8	118.5	119.3	109.4	100.8	92.3	83.9	75.7	66.9
Iron and Steel	-	21.4	50.0	119.1	110.1	101.9	97.4	92.5	86.8	80.4	75.4	70.1	66.2	63.3	61.2	56.7	53.0	49.7	46.7	44.1	41.1
Petroleum Refining	-	3.2	5.9	13.4	15.3	18.8	23.4	26.9	28.8	29.5	30.0	30.1	30.3	30.5	30.8	28.1	25.8	23.4	21.1	18.9	16.6
Smelting and Refining	-	7.8	18.2	43.4	40.2	37.2	35.6	33.8	31.7	29.4	27.6	25.6	24.2	23.1	22.4	20.7	19.4	18.2	17.1	16.1	15.0
Cement	-	2.1	4.2	9.8	10.3	11.5	13.2	14.5	15.0	15.1	15.1	15.0	14.9	14.9	14.9	13.6	12.4	11.3	10.2	9.2	8.1
Misc Manufacturing	-	46.3	107.7	267.3	288.5	294.9	316.3	334.8	345.2	347.2	347.5	340.2	337.6	335.9	335.2	326.7	318.7	311.6	305.1	299.2	279.8
Chemicals	-	8.1	16.4	38.1	41.1	46.2	53.8	59.5	62.5	63.4	63.9	63.4	63.4	63.6	63.8	59.1	54.9	50.8	46.8	43.0	38.6
Mining	-	7.9	17.4	41.3	42.1	43.2	46.4	48.7	49.4	48.9	48.4	47.2	46.5	46.1	45.9	42.9	40.3	37.9	35.5	33.3	30.4
Total	-	109.4	244.3	589.0	611.6	630.3	679.3	716.8	732.5	729.6	725.2	708.9	701.0	695.9	693.5	657.1	625.3	595.2	566.6	539.4	496.5

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Ontario Power Authority

Assessment of Energy Efficiency Potential: 2006–2025

Final Report

October 07, 2005

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Ontario Power Authority

Assessment of Energy Efficiency Potential: 2006–2025

Final Report

October 07, 2005

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1. Executive Summary

- ICF Consulting is pleased to provide the Ontario Power Authority (OPA) with this assessment of the Conservation and Demand Management (CDM) options available for inclusion in Ontario's Integrated Power System Plan (IPSP). We have sought to identify the magnitude of the energy efficiency resource in Ontario and define plausible policy scenarios for achieving that energy efficiency potential.
- To accomplish this, we have melded two complementary approaches that provide significant detail on the nature of energy efficiency potential in Ontario and benchmark our findings against those of other energy efficiency programs and potential studies in North America:
  - ***Accounting Model Framework***—We have employed ICF's Energy Efficiency Potential Model (EEPM) to provide a detailed bottom-up view of what sectors, sub-sectors, and end uses provide the greatest opportunity for energy efficiency improvements. The scenarios modeled include the following (See tables below):
    - **Naturally-Occurring/Static Efficiency:** The Base Forecast includes some natural market-driven efficiency improvements. The Static Efficiency case shows what the forecast would be without this Naturally Occurring Conservation.
    - **Base Forecast:** This is a segmented end use forecast developed by ICF and based on the key drivers of the IESO forecast.
    - **DSM25:** This scenario mimics program intervention that is largely information-based, with financial incentives for measure installation set to 25% of measure incremental cost.
    - **DSM50:** This scenario reflects a program approach with financial incentives set to approximately 50% of measure incremental cost with more intensive marketing and technical assistance efforts.
    - **DSM100:** This scenario assumes incentives equal to 100% of measure incremental costs with intensive recruiting and technical assistance.
    - **DSM100 plus Standards Scenario:** This scenario builds on the rapid market share growth achieved under the DSM100 scenario by implementing aggressive energy efficiency standards starting in 2008.
  - ***Experience-Based Approach***—We have reviewed a wide range of other energy efficiency potential analyses and actual program impacts in an attempt to benchmark the results from the EEPM analysis. This review puts our independent estimate of energy efficiency potential in the context of a broad range of energy efficiency experience, although it is important to recognize several important distinctions between our estimates of potential for Ontario and the results presented for other studies. First, methods used to estimate potential differ in important ways that directly affect both the magnitude and trajectory of estimated potential savings over time. The approach used here explicitly accounts for the amount of efficiency potential estimated to be realized independent of any additional policy interventions. All else being equal, as the time horizon for the analysis lengthens, relatively more potential is realized by "naturally occurring investment", leaving relatively less for capture by policy interventions. The result is that the amounts of potential above and beyond naturally occurring levels tend to shrink over time. The greatest amount of potential available for capture by new policies is in the early years of a time horizon before a significant amount is captured

by naturally-occurring investments. Underlying this behavior is a basic tenet of technology diffusion, i.e. that policy interventions have their greatest effect in speeding the rate of technology adoption, rather than in increasing the absolute size of the market for the technology.

Second, while historical impacts of actual energy efficiency investment programs with projections of efficiency potential can be effective benchmarks for estimates of potential, it is essential to understand the context in which these impacts were realized. For example, the State of California estimates that it has reduced peak load and electricity sales by roughly 15 percent from what they otherwise would have been as the result of policy interventions over the past three decades. Given the IESO estimates of demand, a 15 percent reduction over the 2005 – 2025 period would essentially eliminate growth in Ontario demand. Note, however, that roughly half of California's estimated savings are the result of DSM100 building codes and appliance efficiency standards. The effect of these interventions, and particularly of building codes, is a direct function of underlying growth in the economy. Between 1970 and 2000, the California economy grew by an order of magnitude, and annual growth rates in electricity use averaged above two percent. Moreover, it is difficult to ascertain without a detailed review of claimed savings dating back to 1976, whether in fact all reported savings were verifiable and net of free rider effects.

Tables 1 and 2 summarize the results of our projections of potential expressed as alternative levels of sales and peak demand. Figures 1 and 2 compare our estimates with the estimates of potential from other studies and with estimates based on program experience. The results of other studies and the data pertaining to historical experience were first converted into relative savings (percent) and these were then applied to the baseline Ontario load forecast. The result represents what the forecast of sales would look like if Ontario were to realize these relative levels of savings.

Table 1. Load Forecast Under Achievable Potential Scenarios (Electricity Sales, MWh)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	145,271,108	154,784,424	166,563,340	181,079,862	198,121,155
Base Forecast	143,627,011	149,385,497	155,834,699	163,018,356	170,985,694
DSM25	143,627,011	148,240,144	150,146,510	150,279,326	153,769,936
DSM50	143,627,011	144,409,488	135,398,851	135,787,180	143,293,923
DSM100	143,627,011	138,472,183	127,540,380	132,617,674	142,763,974
DSM100 Plus Standards	143,627,011	122,173,115	123,725,786	132,193,563	142,468,253

Table 2. Load Forecast Under Achievable Potential Scenarios (Peak Demand, MW)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	23,572	26,054	28,896	32,112	35,435
Base Forecast	23,268	24,804	26,430	28,170	30,025
DSM25	23,268	24,604	25,485	26,326	27,749
DSM50	23,268	23,957	23,377	24,133	25,699
DSM100	23,268	23,035	22,138	23,368	25,508
DSM100 Plus Standards	23,268	20,179	21,046	23,120	25,292

Figure 1. Ontario Electricity Sales Scenarios Based on DSM50 Achievable Studies

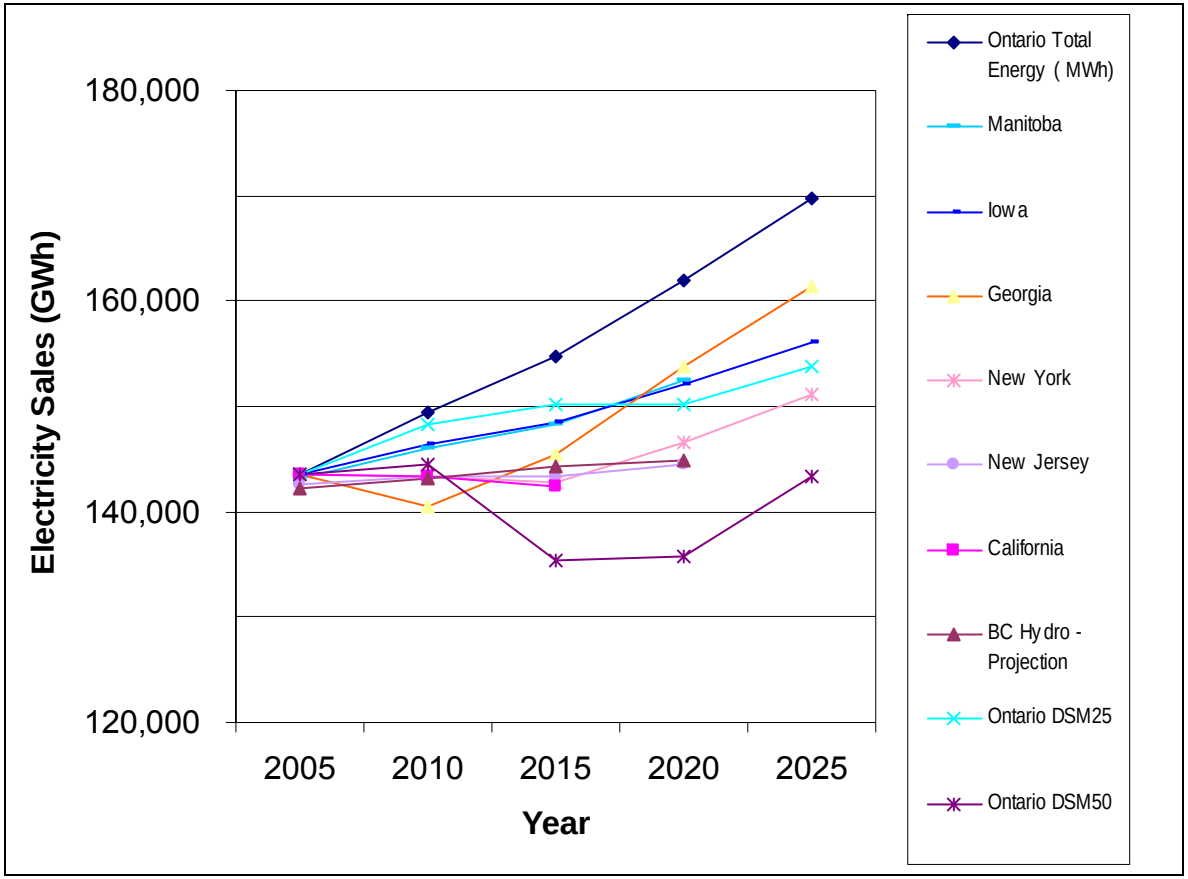
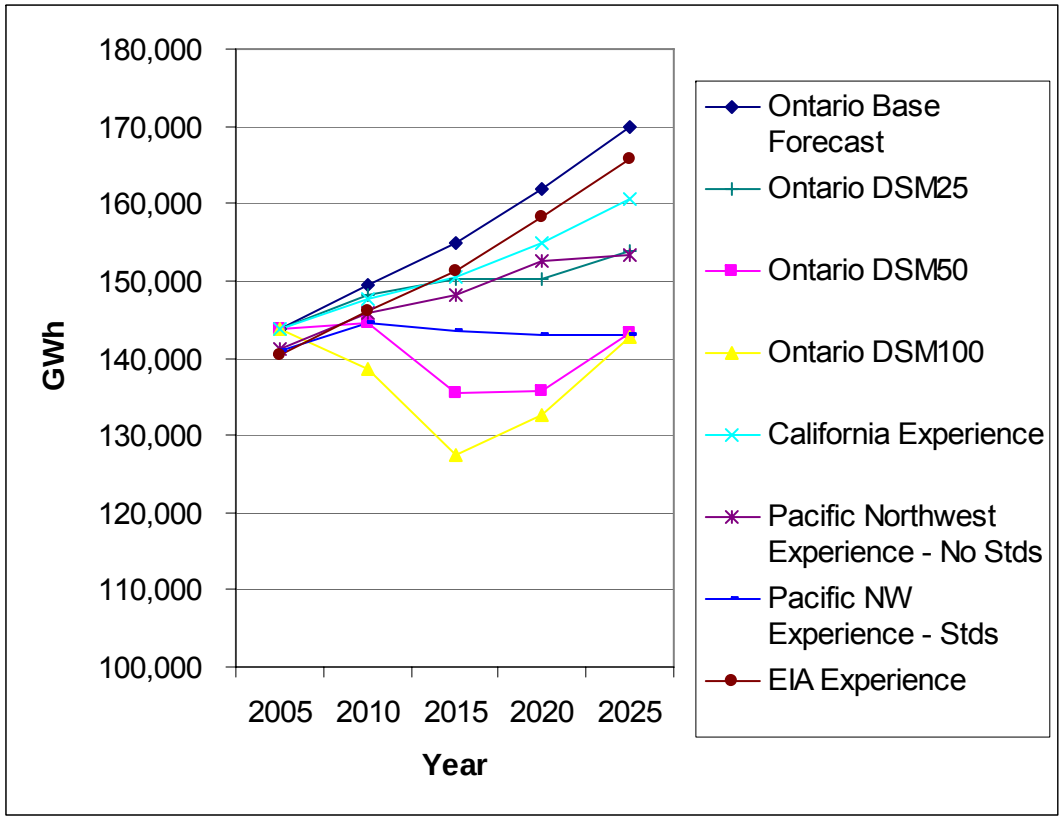


Figure 2. Ontario Electricity Sales Scenarios Based on Program Experience



2. Statement of Study Objectives

- The objective of this assessment is to provide the Ontario Power Authority (OPA) with guidance on the role of energy conservation within its Integrated Power System Plan (IPSP). Specifically, the OPA seeks recommendations pertinent to the development of conservation targets through 2025 within the context of already existing efficiency goals and overall supply mix objectives.
- The OPA seeks further understanding of the energy efficiency portfolio options at its disposal and the risks inherent in each option. Moreover, the OPA requires explicit identification of the action required by government to enact these options.
- ICF intends to meet these objectives through a blending of two approaches. The first approach employs ICF's Energy Efficiency Potential Model (EEPM) to provide estimates of technical, economic, and achievable energy savings potential. To complement these modeling results and place the efficiency potential estimates in the proper context, we have also reviewed other energy efficiency potential estimates and program impacts to summarize the range of both projected and actual industry results.
- In order to use EEPM to more accurately reflect the specific nature of the Ontario market, we have utilized Ontario-specific end use forecast data along with industry data regarding energy efficiency measure costs, applicability, and longevity to model various scenarios of savings potential. The extent to which energy efficiency measures are adopted is dependent on the costs of energy efficiency measures relative to supply side options and the intensity of the projected policy interventions.
- To match the long-term nature of the OPA's planning horizon, we have reviewed the role of advanced energy efficiency technologies in the development of conservation targets. Within the 20-year planning timeframe for this assessment, the technologies available to improve the efficiency of energy-consuming equipment will advance. EEPM mimics this technological evolution in order to properly reflect likely energy efficiency measure market maturation and to provide the OPA with a seamless evaluation of long-term savings potential.
- In addition, this assessment reviews previous industry estimates of savings potential within individual North American jurisdictions. However, many of these studies have been completed only recently, and the plausibility or implausibility of these results may be evident only after the forecast period has passed. Therefore, it is also useful to study the actual historical impact of energy efficiency policies and programs. We have reviewed available industry data on actual program results where sufficient time series of impacts were available as one metric against which to judge the achievability of our projections of energy savings potential. However, care must be taken when attempting a direct comparison with the projections presented here. Program results, particularly over an extended period of time, are affected by a variety of factors including investment levels, the underlying structure of and growth in demand, the method of verifying the program results, and the time period over which the program impacts occurred.
- We believe that the results from this blended approach will assist the OPA in assessing the role of conservation in its long-term needs for energy supply. The results from our EEPM modeling effort provide a detailed analysis using all available data regarding energy efficient technologies. The results of our review of other potential estimates and program impacts will provide a valuable benchmark for validating these EEPM results.

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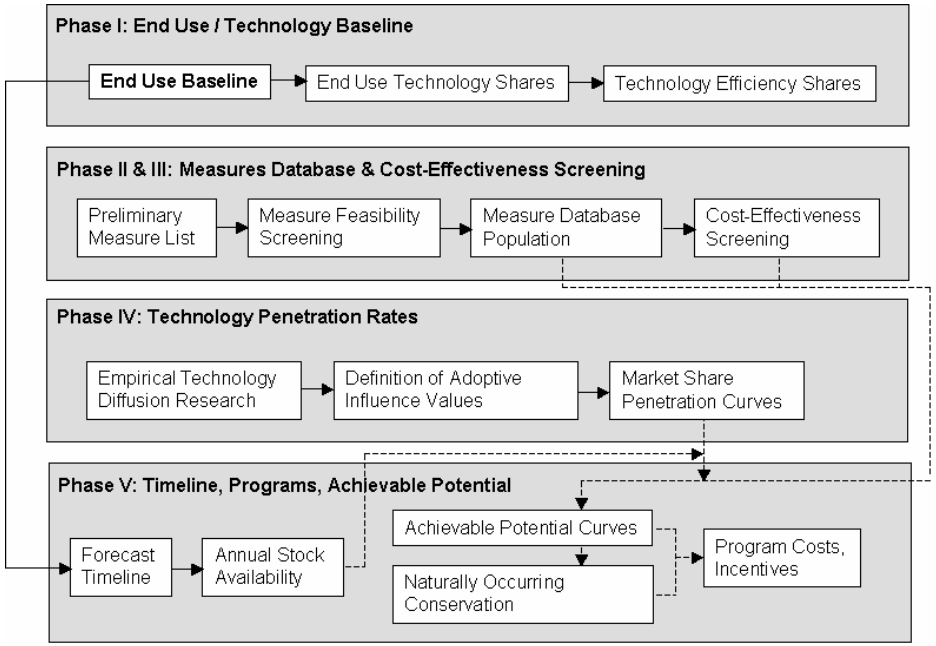
3. Approach

3.1. The Accounting Framework

- ICF Consulting develops and maintains a sophisticated measure-based Energy Efficiency Potential Model (EEPM) that projects the technical, economic, and achievable potential of a wide range of electric and natural gas efficiency upgrades under several market intervention scenarios. Based on a detailed segmentation of energy demand, a database of several hundred energy efficiency measures, and the current market saturations of these measures, EEPM assesses the extent to which program and policy interventions could increase the adoption of energy efficiency technologies. The final results of the modeling process include extensive data on which sectors, sub-sectors, end uses, and measures promise the greatest opportunities for energy efficiency improvement and the likely costs of acquiring that conservation.
- The five-stage EEPM modeling process is outlined in Figure 3.

Figure 3. Overview of EEPM Approach



3.1.1. Establish the Baseline Forecast

- The first step of the EEPM approach is to establish a baseline energy demand forecast segmented by sector, sub-sector, and end use. ICF developed such a segmented forecast using available historical Ontario energy usage data and IESO forecasts.
- In preparing the baseline forecast for this study, growth rates for Employment and Households used in the IESO's *10 Year Outlook* were used to ensure consistency. The IESO forecast projected these values forward to 2015. In order to extend the baseline forecast to 2025, the growth rates assumed by the IESO for the forecast period were extended to 2020 and 2025. ICF recently prepared a Factor Analysis of the growth in electricity consumption from 1990 to 2003 on behalf of the OPA. This project included a detailed analysis of how electricity use by sector, sub-sector and end use had changed over the period and was used as a basis for projecting future electricity use.
- For the residential sector, the projected growth rate in households is virtually unchanged from the historic period. As a result, residential electricity use was forecast based on extending the rate of change for each end use or appliance over the 1990 to 2005 period forward to 2025.
- For the commercial (service) sector, the historic relationship between growth in employment and growth in floor area was used to project future floor area based on the employment growth forecast obtained from the IESO. Electricity use per square meter within the commercial sector has not changed significantly over the historic period. The electricity intensity per square meter for each sub-sector for 2003 was therefore used to project electricity use to 2025 based on the forecast floor area. Available Ontario data include only four specific end uses for the commercial sector with two additional broad "auxiliary" end uses. To add greater specificity to our results, we have estimated what percentages of these auxiliary categories may fall into more specific end uses.
- In the industrial sector, end use data were not available and sub-sector electricity consumption had varied significantly with respect to economic measures over the historic period. In light of the uncertainties around this variability, electricity use was correlated to the IESO's employment index for the industrial sector as a whole. This relationship was then projected over the forecast period based on 2003 electricity intensity levels. Sub-sector electricity use was then derived from this projection by using 2003 shares. Because no end use data were available, we estimated end use segmentations for each sub-sector using data from the US Energy Information Administration Manufacturer Energy Consumption Survey (MECS).
- We further segmented the baseline forecasts to the following levels:
  - **Technology Type—**The technology type describes the class of technology used to deliver the end use energy service. The percentage splits among technology types are derived from available survey data or from best judgment. Note that for many end uses, only one technology type is applicable (i.e., residential refrigerators). We assume that any new load added to an end use is divided among the technology types in the same proportions for each year of the forecast. These proportions are the same regardless of policy intervention scenario. That is, EEPM does not model a scenario in which a program might encourage one technology type over another. All efficiency gains are achieved within the same technology type. As an example of how an end use might be further broken down into technology types, consider the segmentation of commercial interior lighting into the following technology types. Energy use for commercial sector lighting is divided among these technology types so that we can apply specific energy efficiency measures to the appropriate technology type.

- 4-foot fluorescent fixtures
- 8-foot fluorescent fixtures
- Incandescent or other medium screw-based lamp fixtures
- Exit signs
- High intensity discharge fixtures

– **Efficiency—**For each technology type, the baseline forecast is further segmented into two or three efficiency levels. Some technology types have three efficiency levels, while others only have two (Base and High Efficiency). To determine this initial segmentation, we utilize whatever energy efficiency program or installed saturation data are available and, when necessary, estimate saturations where these data are not available. These initial saturations are used to establish what proportion of load can be attributed to each efficiency level. As the model projects adoption of energy efficiency measures into the future, any new load or equipment being replaced at the end of its life is assigned to an efficiency level based on EEPM's projected market shares for high efficiency equipment in that year. The process of projecting future market shares for high efficiency measures will be discussed in greater detail below. The three efficiency levels are as follows:

- Existing: The Existing efficiency level describes older equipment that is now below current codes or standard practice. Typically, any equipment bought today will be more efficient than equipment at the Existing level. For our commercial lighting example, T12 lamps with magnetic ballasts are the appropriate Existing efficiency level for 4-foot fluorescent fixtures. T12 fixtures are still used, but when replaced, very few are replaced with this older efficiency level.
- Base: The Base efficiency level describes current standard efficiency level equipment. Regular T8 lamps with electronic ballasts would represent the current standard practice.
- High Efficiency: The High Efficiency level represents a commercially available high efficiency alternative to the Base level equipment. Super T8 fixtures and ballasts would be the high efficiency alternative to regular T8 lamps and ballasts.

– To clarify, these initial **saturations** among the efficiency levels define what proportion of total technology type electricity is used in each level in the base year. Over the forecast horizon, however, these saturations will change based on **market shares** that describe what proportion of new load and replaced equipment will be bought at each efficiency level. EEPM dynamically projects this stock turnover and determines how the marginal market shares of energy efficient equipment impact the saturation of the equipment over time.

3.1.2. Measure Database and Cost-Effectiveness Screening

- The development of the energy efficiency measures database involved three primary steps.
  – A list of approximately 300 energy efficiency measures to be considered for the residential, commercial, and industrial sectors has been compiled for EEPM. These measures represent both replace-on-fail and retrofit options for all major end uses. The measures have been screened for applicability and feasibility for potential energy efficiency programs.

  - Measure data stored for each measure in the EEPM database were cross-checked against existing Ontario and Canadian sources.[1] Data elements associated with each element include incremental capital and installation costs, O&M cost, measure life, and per unit energy and demand savings. Based on our review of other Canadian energy efficiency potential studies and DSM analyses, the measure cost and savings data used in EEPM are consistent with the Ontario climate and market.
  - End use savings factors are calculated by first determining the amount of building stock, if any, for a particular building type that can be affected by a particular measure. For instance, a refrigeration measure would be applicable to a grocery or warehouse building, but not to an office building. Then, each measure for a specific end use that had a benefit/cost ratio of 1.0 or greater was aggregated with others in that end use to arrive at an end use level savings factor. For instance, if two cost-effective measures exist for the lighting end use, each with savings potential of 25%, the measures are assumed to be implemented in series so that the overall savings due to application of both measures would be 43.7%. Finally the end use savings factors for all cost effective measures were applied to their respective end use loads to determine savings.

- The cost-effectiveness screening of energy efficiency measures included several steps. The screening process uses what is known as the Technical Cost Test (TCT), similar to the TRC test[2], which compares the incremental measure cost with savings valued at utility avoided costs. The screening also compared the incremental measure cost for each measure with the present value of a future stream of estimated average retail prices (for the Participant Cost Test). Measures with a benefit/cost ratio of 1.0 or greater for the Participant Cost Test were considered eligible for adoption by consumers in developing estimates of naturally occurring energy efficiency. Measures passing the TCT became part of the set of efficiency measures considered in developing estimates of achievable potential.

3.1.3. Determining the Technical, Economic, and Achievable Potential for Energy Efficiency

Energy Efficiency Potential Defined

- **Technical potential** quantifies the savings that could be realized if energy efficiency measures were applied in all technically feasible instances, regardless of cost. As is often the case, we estimate technical potential assuming that this change-out occurs immediately. Technical potential is therefore useful as a broad gauge of the economy's inefficiency in the territory of interest.
- **Economic potential** is the subset of technical potential that is cost-effective from a TCT perspective. As for technical potential, economic potential assumes that all relevant energy efficiency improvements occur instantaneously.

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[1] For a study with a longer timeframe, we would also include some refinement of our energy efficiency measure database. However, the database has been recently updated, and we have also completed building simulations for weather-sensitive measures that reflect the climate of the northern US—a reasonable approximation of energy efficiency measure performance in Ontario.

[2] The Technical Cost Test essentially compares the incremental installation cost of a measure with the avoided cost and differs from the Total Resource Cost Test in that at this stage, program administrative costs are not considered.

- **Achievable potential** typically is defined as the amount of cost-effective energy efficiency improvement expected to be captured as the result of specific policy or program actions, over-and-above the efficiency improvements attributable to normal consumer and market behavior and existing conservation policies and programs. This class of efficiency potential is distinguished from technical and economic potential in three important ways.
  - First, as the term implies, achievable potential is defined in terms of what realistically can be captured by explicit actions.
  - Second, and following from the first point, achievable potential is time-dependent. Achievable potential only can be realized by convincing consumers to replace existing equipment and practices with new, more efficient equipment and practices. It is often the case that consumers are most easily convinced to adopt high efficiency alternatives when they must make equipment replacement decisions anyway. Therefore, what is considered achievable potential grows over time as an increasing amount of the existing equipment stock reaches the end of its useful life.
  - Finally, achievable potential intrinsically is a function of consumer behavior. The amount of potential one might expect is based on assumptions about what consumers will do when faced with various policy and program interventions. Because estimates of achievable potential consider this difficult-to-predict consumer behavior, they are inherently more uncertain than estimates of technical or economic potential.
- To project achievable potential, EEPM estimates the adoption of cost-effective energy efficiency measures over time. The derivation of achievable potential involves several steps:
  - First, EEPM estimates what consumers will do in response to market forces, existing programs, and potential new programs. This requires some method to simulate or forecast the future market penetration of energy efficiency measures. The approach we employ recognizes that consumer choices are based on a wide variety of influences beyond the simple financial aspects of the purchase decision. These influences include consumer awareness of the product, the perceived advantages the product confers beyond energy savings (e.g., convenience, appearance), the perceived performance risk associated with the product, the status it might convey, and so on.[3] This approach is based on the observation that the best predictor of a product's future market share is its past and current market share.[4]
    - To implement this analysis, a straightforward mathematical function is employed to simulate the growth of energy efficiency measure market share over time for market-driven, existing program-driven and achievable energy efficiency improvements (See Equation 1). This function incorporates three key elements:

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[3] For a complete discussion of the factors that affect consumer decision making and how these factors combine to affect market penetration, see, Everett M. Rogers. *Diffusion of Innovations*. New York: The Free Press. 1995.

[4] See, for example, Shipley, Anna M, et.al. "Market Diffusion Theory and the Penetration of Combined Heat and Power," *ACEEE Summer Study in Buildings*,. Washington, American Council for an Energy Efficient Economy. 2002, Blackman, A Wade. "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change* 6,41-63 (1974), Packey, Daniel J. *Market Penetration of New Energy Technologies*, National Renewable Energy Laboratory, NREL/TP-462-4860. 1993, and DeCanio, Stephen J., and Laitner, John A. "Modeling Technological Change in Energy Demand Forecasting," *Technological Forecasting and Social Change* 55, 249-263 (1997).

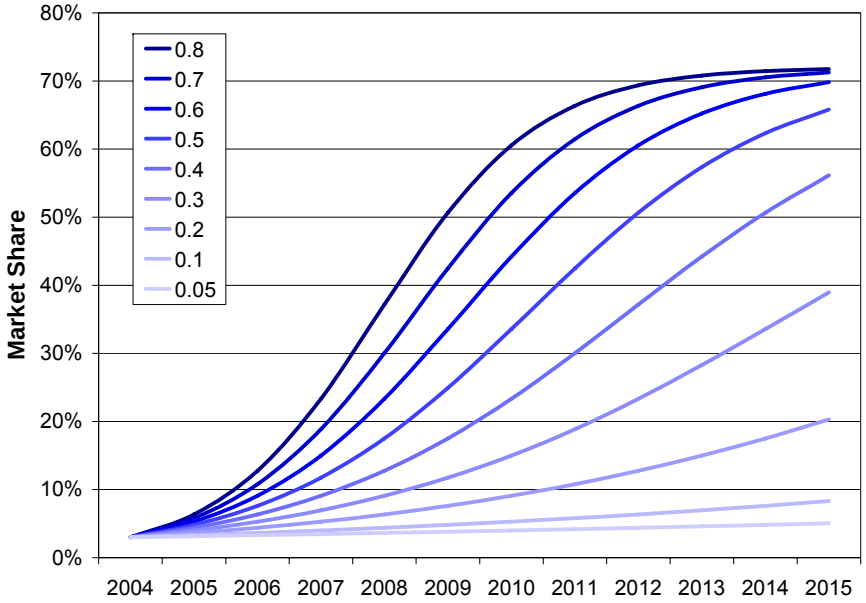
- MS_0: Market share of the technology or product in an initial year
- C: The product's assumed maximum market share; and
- A: A parameter representing "adoptive influence," which influences the speed at which a technology gains share in the market.

Equation 1. Equation for Market Share in Year *t*

$$MS_t = \frac{C}{1 + e^{\left[-At + \ln\left(\frac{1 - MS_0 / C}{MS_0 / C}\right)\right]}}$$

- The adoptive influence parameter is estimated from available market share data. The magnitude of the parameter, which can vary between 0.0 and 1.0, determines the shape or compression of the S-shaped adoption curve, which in turn controls how fast a measure/technology/product diffuses through the market (See Figure 4).
- Review of available market share data associated with energy efficiency programs shows that the adoptive influence can be significantly higher for measures affected by these programs than is the case for measures that are not being directly influenced by program intervention.
  - The marginal market share projected by this adoptive influence approach represents the annual fraction of replacement and new load that "chooses" energy efficiency as opposed to standard efficiency equipment and practices. The total saturation of energy efficiency measures grows through time as a direct function of the marginal share. Within the model, the adoptive influence parameter increases the marginal market share over time. The higher this value, the greater the annual increase in market share and the faster the increase in total saturation.

Figure 4. Projected Market Adoption Under a Range of Adoptive Influence Values



- EEPM also tracks the turnover of energy consuming equipment.
  - For each year, a certain amount of energy consuming equipment must be replaced and new equipment is added. As existing equipment reaches the end of its useful life and is replaced, new equipment is purchased at either a base or high-efficiency level as determined by the projected market shares for high-efficiency equipment.
  - Replace-on-fail measures are only available for implementation as older equipment is replaced, but retrofit measures may be implemented at any time. Retrofit measures include:
    - Measures that do not replace any existing equipment (e.g., pipe insulation added to non-insulated pipes).
    - Measures that replace existing equipment but are cost-effective even when the full cost of the new high-efficiency equipment is considered. For example, the incremental cost of a high-efficiency 15 SEER residential central air conditioning unit is the difference in cost between a 15 SEER unit and a standard 13 SEER unit. For an equipment replacement such as this, cost-effectiveness for replace-

on-fail is calculated based on this incremental cost and the incremental savings achieved by selecting a 15 SEER over a 13 SEER unit. However, if the incremental savings achieved by the 15 SEER unit were enough to overcome the *full* cost of the equipment and installation, the existing unit may be replaced by the 15 SEER at any time.

- Based on our research of historical energy efficiency program influence on market shares, we have calibrated EEPM's market adoption curves to several scenarios:
  - **Naturally Occurring—**This scenario reflects efficiency gains from turnover of older equipment to current standard equipment and the adoption of high-efficiency equipment due to natural market forces and existing energy efficiency programs. Even in the absence of additional program or policy interventions, consumers will take actions that improve the efficiency of their energy-consuming equipment. These energy savings make up what we call naturally occurring conservation. Naturally occurring conservation is the result of three general classes of structural market changes and consumer decisions:
    - Equipment Retirement—Some proportion of currently installed equipment is older and less efficient than current standard equipment. As this stock of equipment reaches the end of its useful life, it will be replaced with current standard efficiency equipment. We term the savings achieved from this turnover as "equipment retirement."
    - Market-Driven Conservation—Some consumers will independently choose the high efficiency technology based on the prices they face for the equipment in the market and their perceptions of the costs and benefits of choosing the efficient option. The energy efficiency gain that results from these choices is sometimes called "market-driven."
    - Existing Program-Driven Conservation—Other consumers will tend to choose standard efficiency options unless offered some incentive to buy more efficient equipment. Consumers who make energy efficiency investments by taking advantage of incentive programs already offered contribute to what is referred to as "existing program-driven conservation."
  - **DSM25—**This scenario is consistent with a portfolio of energy efficiency programs offering modest financial incentives (~25% of incremental costs) with limited marketing and outreach.
  - **DSM50—**This scenario is consistent with a portfolio of energy efficiency programs offering more generous financial incentives (~50% of incremental costs) with more extensive marketing and outreach.
  - **DSM100—**This scenario is consistent with a portfolio of energy efficiency programs offering highly aggressive incentives (~100% of incremental costs) with extensive marketing and outreach efforts. This type of scenario is considered to reflect the maximum possible achievable potential. Efficiency potential in the DSM100 case still does not capture all economic potential. Even with financial incentives covering the full cost of efficient equipment, some customers will not be influenced to invest in energy efficiency.
- Because we are most interested in the extent to which policies and programs can achieve savings above and beyond natural conservation, it is important to understand the concepts underlying naturally occurring conservation. There are a few points to keep in mind:

- First, because naturally occurring conservation will occur even in the absence of new policy or program interventions, it is embedded within the baseline forecast. That is, without naturally occurring conservation, the baseline forecast would be higher.
- Second, given a long time horizon, naturally occurring conservation will catch up to any of the modeled policy scenarios. Even under the naturally occurring scenario, market shares of high-efficiency technologies will rise slowly over time. Eventually, these market shares reach their upper limit and cannot grow further. As a result, the various policy scenarios will tend to converge with the baseline forecast over the long-term as the naturally occurring scenario slowly captures the same savings achieved by the policy scenarios. The root cause of this phenomenon is that we only record savings for energy efficiency measures that we know to be commercially available now or in the near future. Given enough time, these energy efficiency opportunities will often be extensively adopted regardless of additional program interventions. To partially address this effect, we have incorporated a second generation of energy efficiency measures into the EEPM structure as emerging technologies.

3.1.4. Treatment of Emerging Technologies

- As the market for a particular energy efficiency technology matures, it may be reasonable to make that technology the new standard. This is particularly relevant for a study with a 20-year horizon such as this one.
- To model the changing technological landscape, we have included emerging or advanced energy efficiency technologies in our analysis for the OPA. Emerging technologies have been incorporated as follows:
  - As for any other energy efficiency measure, cost and savings information for each emerging technology have been recorded in EEPM's energy efficiency measure database.
  - Once the market share of an energy efficiency measure approaches its market share cap, EEPM sets this energy efficiency measure as the new standard efficiency option. The emerging efficiency technology is then introduced with an initial market share of about 10%. This emerging technology then is able to grow its market share over time as the new high efficiency option.
  - It is also possible to set a particular year in which a new standard is to take effect. In that year, the energy efficiency measure is set as the standard efficiency option and the emerging technology enters the market as the new high efficiency option.
- This process, in essence, models the transformation of the market to high-efficiency equipment and the subsequent entrance into the market of the next generation of high-efficiency equipment. This delays substantially the convergence of the policy scenarios with the naturally occurring scenario. Essentially, it expands the opportunities available to programs for improving energy efficiency.
- We should note that the technical applicability and economics of these emerging technologies is more speculative than for current commercially available technologies, but it is important to address broad technological change over a 20-year time frame.

3.1.5. Description of the Scenarios and Key Data Sources

Scenarios of Achievable Potential

- In conjunction with the OPA, we have developed several scenarios of achievable potential to describe the impacts of different types of policy interventions:
  - **Naturally-Occurring/Static Efficiency:** Naturally occurring conservation reflects efficiency gains from turnover of older equipment to current standard equipment and the adoption of high-efficiency equipment due to natural market forces and existing energy efficiency programs. The scenario is calibrated to adoptive influence values ($A \approx 0.125$) reflecting the adoption behavior characteristic of an environment in which there is a relatively high level of awareness of energy efficiency and some history of program activity, but no current subsidized energy efficiency activity beyond existing codes and standards. The **Base Forecast** includes this level of naturally occurring conservation, so we have added naturally occurring conservation on top of the Base Forecast in order to represent load growth in a state of Static Efficiency where no efficiency gains are realized.
  - **Base Forecast:** This is the segmented end use forecast developed by ICF and based on the key drivers in the IESO forecast.
  - **DSM25:** This scenario attempts to mimic program intervention that is largely information-based, with financial incentives for measure installation set to 25% of measure incremental cost. ($A \approx 0.25$)
  - **DSM50:** This scenario reflects a fairly common program approach wherein, financial incentives are set equal to approximately 50% of measure incremental cost. In addition, program implementation costs are assumed to be higher due to more intensive marketing and technical assistance efforts. ($A \approx 0.50$)
  - **DSM100:** Here we assume that incentives are equal to 100% of measure incremental costs and program implementation costs are correspondingly higher reflecting intensive recruiting and technical assistance. ($A \approx 0.75$)
  - **DSM100 plus Aggressive Standards Scenario:** In our work for the OPA we have built additional structure into the accounting framework to allow us to simulate the introduction of emerging technologies. This structure can be used to represent imposition of a broad range of generic standards. For example, switching the year at which the advanced technologies begin to enter the market we convert the current high efficient measures to standards. For this scenario, we assume that Ontario implements a series of aggressive standards starting in 2008 to build upon the rapid market share growth achieved under the DSM100 scenario. Once these standards are implemented, the minimum efficiency equipment that can be bought is the high-efficiency category. At the same time, an emerging technology enters the market at a low initial market share and is gradually accelerated into the market.

3.1.6. Key data sources

There are three basic types of data required for the Energy Efficiency Potential Model approach.[5]

- **Load Data—**These data include any available electricity sales or peak demand forecasts as well as segmentations of load by sectors, sub-sector, end use, and technology type. The electricity sales forecast was developed as described above from historical energy consumption trends and the IESO's projected energy demand drivers. This sales forecast was converted to summer peak demand using the IESO's peak demand forecast and a series of load factors specific to the northern United States climate.
- **Utility Cost Data—**Avoided utility costs of electricity are used to determine the resource value of conserved energy and determine cost-effectiveness of energy efficiency measures and program portfolios. Our source for these data was the recent Navigant Consulting study on avoided costs presented to Hydro One Networks.[6]
- **Energy Efficiency Market Data—**We cross-checked EEPM's measure database against recent Canadian energy efficiency potential studies and DSM analyses to determine the reasonableness of our cost and savings assumptions for the Ontario climate and equipment market. We observed no systematic bias in our energy efficiency market data relative to that which was available for Ontario.

3.2. The Experience-Based Approach

- Dozens of estimates of energy efficiency potential have been prepared for jurisdictions in North America over the past decade providing a rich pool of information against which the results of the Accounting approach described above can be compared. This information on potential can be placed in context by also examining the results of actual DSM program implementation. This section briefly summarizes estimates of potential and program impacts gathered from a wide range of sources. Where the data permit, estimates of potential and program impact expressed in relative terms (percentage reduction in energy or peak) are applied to the base energy forecast used in the Accounting Framework to illustrate the absolute magnitude of savings if such reductions were achieved in Ontario.
- In a number of cases the time horizon for which estimates of DSM potential were prepared in these other studies differs from that used in this assessment. In cases in which the forecast horizons used for these other studies extended for less than the 20-year horizon used here, no attempt was made to extrapolate the results. Absent a much more detailed understanding of the methods underlying these studies such extrapolation would create an unrealistic comparison with the estimates that we have prepared using the accounting method described above. Where only a single year estimate of potential was reported (e.g. total achievable potential by the year 2015), relative savings for preceding

[5] For a study with a longer timeframe, we would also include some refinement of our energy efficiency measure database. However, the database has been recently updated, and we have also completed building simulations for weather-sensitive measures that reflect the climate of the northern US—a reasonable approximation of energy efficiency measure performance in Ontario.

[6] Navigant Consulting, *Avoided Cost Analysis for the Evaluation of CDM Measures*. June 2005.

years were estimated using linear extrapolation. Although the adoption of energy efficiency measures typically follows an S-shaped path, we believe the linear extrapolation used here is sufficient for intra-year comparisons.

3.2.1. Data Sources

Estimates of Efficiency Potential

We have examined the results of twenty one relatively recent estimates of efficiency potential from the US and Canada. The studies are summarized in the following table.

Table 3. Index of Reviewed Energy Efficiency Potential Studies

Organization Name and Author	Title	Year	Jurisdiction	Sectors Considered
ACEEE Margaret Suozzo, Steven Nadel, Jeff Harris, Tom Eckman	Selecting Targets for New Market Transformation Initiatives in the Northwest	1998	Oregon, Washington	Residential, Commercial & Industrial
ACEEE R. Neal Elliott	Electricity Consumption and the Potential for Electric Energy Savings in the Manufacturing Sector	1994	U.S.	Manufacturing
Optimal Energy John Plunkett Phil Mosenthal Chris Neme	Vermont Department of Public Service Electric and Economic Impacts of Maximum Achievable Statewide Efficiency Savings 2003-2012	2002	Vermont	Residential, Commercial & Industrial
RLW Analytics, Inc.	The Remaining Electric Energy Efficiency Opportunities in Massachusetts Final Report	2001	Mass.	Residential, Commercial & Industrial
Kema-Xenergy, Inc. Fred Coito & Mike Rufo	California Statewide Commercial Sector Energy Efficiency Potential Study	2002	California	Commercial
Kema-Xenergy, Inc. Fred Coito & Mike Rufo	California Statewide Residential Sector Energy Efficiency Potential Study	2003	California	Residential
BC Hydro	BC Hydro Conservation Potential Review 2002 Summary Report	2003	British Columbia	Residential, Commercial & Industrial

Organization Name and Author	Title	Year	Jurisdiction	Sectors Considered
Ecotope, Inc. ACEEE, and Tellus Institute Shelly Borrelli, David Baylon	Energy Efficiency and Conservation Measure Resource Assessment for the Residential, Commercial, Industrial and Agricultural Sectors	2003	Oregon	Residential, Commercial & Industrial
GDS Associates and Quantum Consulting Jeff Schlegel, Richard Spellman	Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region - Final Report	2004	Connecticut	Residential, Commercial & Industrial
Southwest Energy Efficiency Project Howard Geller, Neal Elliott, Toru Kubo, Steve Nabel, Anna Shipley	The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest	2002	Six states in the SW US	Residential, Commercial & Industrial
New York State Energy Research and Development Authority (NYSERDA)	Energy Efficiency and Renewable Energy Resource Development Potential in New York State	2003	New York	Residential, Commercial & Industrial
Oak Ridge National Laboratory (ORNL) Stan W. Hadley	The Potential for Energy Efficiency in the State of Iowa	2001	Iowa	Residential, Commercial & Industrial
Tellus Institute	An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah	2001	Utah	Residential, Commercial, & Industrial
Richard Brown	Estimates of the Achievable Potential for Energy Efficiency Improvements in U.S. Residences	1993	U.S.	Residential
Synapse Energy Economics	Repowering the Midwest: The Clean Energy Development Plan for the Heartland	2001	Illinois, Indiana, Iowa, Michigan, Minnesota, Nebraska, North Dakota, Ohio, South Dakota	Residential, Commercial & Industrial
ACEEE Marshall Goldberg, Martin Kushler, Steven Nadel	Energy Efficiency and Economic Development in Illinois	1998	Illinois	Residential, Commercial & Industrial
KEMA	New Jersey Energy Efficiency and Distributed Generation Market Assessment	2004	New Jersey	Residential, Commercial & Industrial
Optimal Energy	Economically Achievable Energy Efficiency Potential in New England	2004	New England	Total
Demand Side Energy / Marbek	Manitoba Hydro DSM Market Potential Study	2003	Manitoba (Manitoba Hydro Territory)	Residential, Commercial & Industrial

Organization Name and Author	Title	Year	Jurisdiction	Sectors Considered
ICF Consulting	Assessment of Energy Efficiency Potential In Georgia	2005	Georgia	Residential, Commercial & Industrial
ICF Consulting	Estimate of Energy Efficiency Potential for Wisconsin Public Service	2004	Wisconsin Public Service Co. territory	Residential, Commercial & Industrial

Estimates of Program Impact

- Discussions with the OPA suggested an interest in being able to apply the results of best practice program results to baseline Ontario load as an indication of the impact that adoption of similar programs might have in Ontario. Unfortunately, although there is a growing literature on best practice and exemplary programs, the information readily available for these programs does not allow straightforward translation into potential impacts in Ontario. Program results tend to be expressed in absolute terms (GWh or MW saved). The time allowed for this project did not allow us to collect base sales and demand data for each of the utilities for which we have program impact information. Moreover, much of the information pertaining to the achievements of best practice US energy efficiency programs is presented in relatively short time series and for specific programs as opposed to energy efficiency investment portfolios. In our experience it is a relatively more common accomplishment to achieve significant energy or demand savings from individual programs over several years than to maintain such success across a portfolio of programs and over a twenty year period. At least within the US and Canada we are not aware of a single jurisdiction that has maintained a consistent and significant investment over such an extended period. For example, even though the State of California has one of the longest and most accomplished energy efficiency track records on the continent, the actual investment and annual savings profile shows very pronounced oscillation, with annual spending ranging from $100 million to over $300 million.
- We have nevertheless compiled a partial list of those programs shown in Table 4, and should the OPA wish, we can pursue the base sales and demand data that would allow conversion of program results in a form that could be applied to the Ontario case.

Table 4. Reviewed Energy Efficiency Program Data

Organization	Program	Year	Jurisdiction	Sector	Target Population	% Participation	Total Period GWh Savings	Total Period Costs / Budget (mil $)
Efficiency Vermont	Multi-family Residential Low-Income Program	1997–2002	Vermont	Residential	Unknown	Unknown	12.3	8.5
New Jersey Clean Energy Collaborative	Cool Advantage—Residential Air-conditioning	2002	New Jersey	Residential	50,000 (annual)	30%	14.0	17.0
NYSERDA	Keep Cool—Residential Air-conditioning	2002	New York	Residential	Unknown	Unknown	104.0	20.0
Proctor Engineering	Check Me!—Air-conditioning	2002	California	Residential, Commercial	Entire US	Unknown	33.1	4.5
Northeast Residential Energy Star Appliances Initiative	Appliances	2002	New England, New York	Residential	2.2 mil	22% (2002) 2.4% (1998–2002)	0.8	0.2
SMUD	Old Refrigerator Pickup and Recycling	2002	Sacramento, CA	Residential	450,000	2%	13.7	1.2
Southern California Edison	Residential Appliance Recycling Program	2002	Southern California	Residential	3.9 mil	5-10%	44.6	4.8
Texas	Texas Energy Star Homes Program	2000–2002	Houston and Dallas, TX	Residential	78,000	15-20%	41.8	9.6
Austin, Texas	Green Buildings Program	2002	Austin, TX	Residential	1,200	57%	12.3	1.2
Northeast Energy Efficiency Partnership	Northeast Regional Energy Star Lighting Program	2001	Northeast	Residential	5.2 mil	Unknown	167.0	17.0
Northwest Energy Efficiency Alliance	Energy Star Residential Windows Program	1998–2001	Oregon, Washington, Montana, Idaho	Residential	New construction	75%	364.0	1.8
National Grid	Small Business Services	2002	New England	Commercial	77,000	33%	13.6	1.0

Organization	Program	Year	Jurisdiction	Sector	Target Population	% Participation	Total Period GWh Savings	Total Period Costs / Budget (mil $)
Avista Utilities	Rooftop HVAC Maintenance Service	2001	Spokane, WA	Commercial	18,000	11%	13.0	1.8
Portland General Electric	Existing Building Commissioning	2001	Portland, OR	Commercial	Unknown	Unknown	6.5	0.3
US EPA	Energy Star Monitor Power Management Program	2002	US	Commercial	Unknown	Unknown	232.0	0.5
Pacific Gas & Electric	Compressed Air Management Program	2003	San Francisco, CA	Commercial, Industrial	14,000	1%	9.4	0.2
Xcel Energy	Lighting	2001–2003	Minnesota	Commercial, Industrial	Unknown	Unknown	204.2	12.2
SMUD	Cool Roof	2001–2002	Sacramento, CA	Commercial	Unknown	Unknown	0.6	1.0
Pacific Gas & Electric	Upstream Residential Lighting Program	2001–2003	Northern California	Residential, Commercial	4.5 mil	8%	1521.5	34.9
SMUD	Shade Tree Program	2001–2003	Sacramento, CA	Residential	350,000	37%	14.4	4.8
Wisconsin Energy Conservation Commission	Energy Star Products	2001–2002	Wisconsin	Residential	2.3 mil	24%	25.5	18.8
Wisconsin Energy Conservation Commission	Energy Star Homes	2001–2002	Wisconsin	Residential	20,000	4%	0.4	0.3
Wisconsin Energy Conservation Commission	Home Performance	2001–2002	Wisconsin	Residential	1.4 mil	1%	5.1	3.8
Connecticut Light and Power, Western Massachusetts Electricity Company	Small Business Energy Advantage	2001–2003	Connecticut, Massachusetts	Commercial	108,000	35%	58.3	21.0

- Among the programs reviewed, some of the overall findings that have lead to greater penetration and increased savings were:
  - Residential customers benefited from programs with point-of-purchase discounts and reduced administrative requirements. In addition, residential programs often featured prompt rebates, and hands-on customer service contact between customers and the utility or a contractor.
  - Commercial customers benefited from programs with trained sales and implementation staff. Commercial programs were also more likely to have upstream involvement, with manufacturers, through the use of innovative marketing techniques.
  - Other characteristics not limited to a specific sector included advanced market research and increased community-based marketing and advertising. Turnkey installation was also important in effective participation and implementation. Successful programs also featured close relationships among utilities, state agencies, and manufacturers. Also, in many of the programs, manufacturers were interested in increasing market share and promotional activity rather than financial incentives.
- We have, as indicated, identified several sources of time series program impact data that can be matched to sales and demand data to yield percentage reductions in load resulting from long-term energy efficiency portfolio implementation.
  - The US Department of Energy's Energy Information Administration (EIA) collected annual estimates of energy efficiency program impacts from the mid-1980s through 2002. These estimates when applied to historic sales and demand data for US utilities support an estimate of relative impact that can be compared with our estimates of achievable potential in Ontario.
  - The Regional Technical Forum associated with the Northwest Power Planning Council publishes annual energy efficiency program savings data dating to the 1980s as well as historical load data. The Pacific Northwest, by most accounts, has had some of the most consistently high levels of energy efficiency investment over the past two decades of any area aside from California. We have used these data to calculate annual percentage reductions in sales due to utility energy efficiency programs. Note that close to half of the total electricity reduction due to energy efficiency has been attributed to the effects of building codes and appliance standards. These impacts have been netted out of the data presented to enable a comparison of impacts of similar policy interventions.
  - The California Energy Commission (CEC) has been tracking energy efficiency impacts upon total load from the mid-1970s through the present. More than half of the savings have been as a result of utility programs, with the remainder from building standards and appliance standards. We have used these data to calculate annual percentage reductions in sales and demand, but again have subtracted the savings attributable to codes and standards..
  - We have applied these relative savings to the IESO forecast of electricity sales in Ontario as an indication of what the Ontario energy efficiency profile might look like if the Province were able to realize this same level of savings. However, it is important to not draw broad conclusions from this comparison. When examining such historical series, it often is not possible to determine the fraction of savings that are net of what would have occurred as the result of natural market forces. Generally, the theory and practice of program evaluation was not particularly sophisticated in the 1980s and early 1990s and it is likely that a substantial fraction of savings booked in early years of the California and Pacific Northwest experiences were attributed to information and education programs. Finally, as was noted earlier, energy

efficiency savings are related to the underlying growth in economic and electricity demand. Generally speaking, savings opportunities are larger in faster growing systems. This is particularly true with respect to energy efficiency policies and investments targeting new construction.

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4. Results

4.1. Accounting Approach

- This section presents the results of the accounting model approach. The results include estimates of instantaneous technical and economic potential as well as annual projections of achievable potential under a variety of program scenarios.

4.1.1. Technical and Economic Potential

- The tables and figures below show 2004 electricity sales and estimated peak demand for each sector along with our estimates of instantaneous technical and economic potential based on that load.

Table 5. Technical and Economic Potential

		MWh			MW	
Forecast	2004 Load	Technical Potential	Economic Potential	2004 Load	Technical Potential	Economic Potential
Residential	46,941,752	11,531,877	9,641,883	6,943	2,898	1,758
Commercial	52,867,545	16,620,946	12,408,578	10,241	3,859	2,282
Industrial	41,863,050	8,406,146	7,501,047	7,363	1,466	1,209
Total	141,672,347	36,558,969	29,551,508	24,546	8,223	5,249

Figure 5. 2004 Load, Technical & Economic Potential by Sector (Electricity Sales)

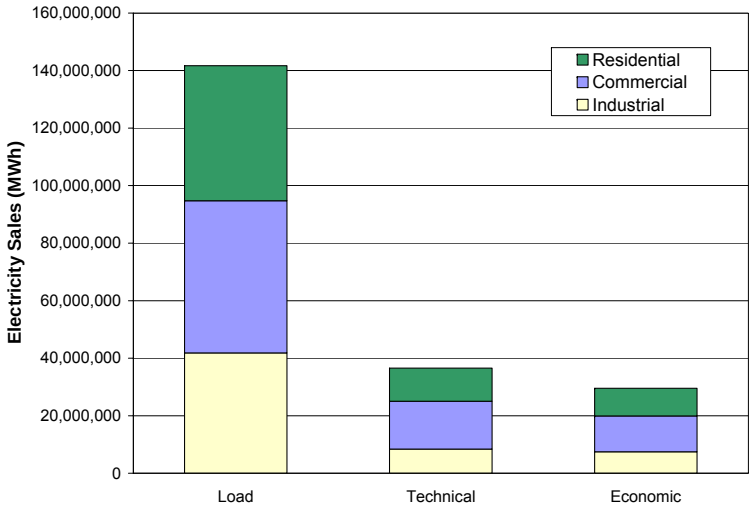
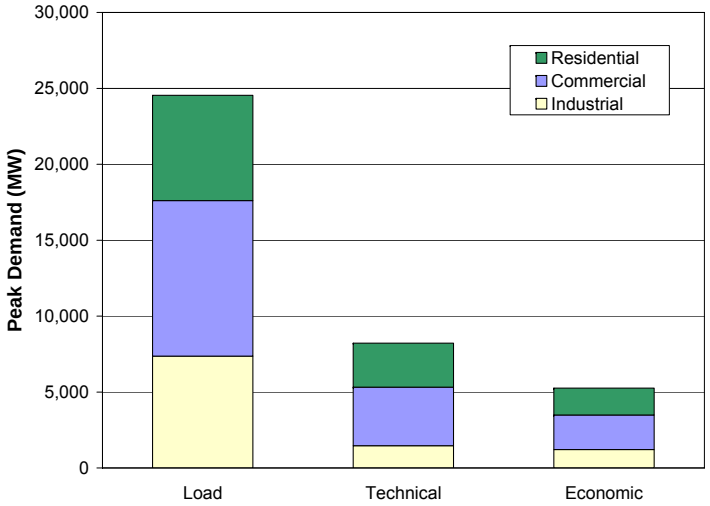


Figure 6. 2004 Load, Technical & Economic Potential by Sector (Peak Demand)



4.1.2. Naturally Occurring and Achievable Scenarios

Overview

- The tables and figures on the following pages summarize our EEPM-based accounting model results for achievable energy efficiency potential from 2005 to 2025. Fully detailed tables and graphs of our results may be found in the appendix.
- The following are the achievable potential scenarios modeled for this study:
  - **Naturally-Occurring/Static Efficiency:** Naturally occurring conservation reflects efficiency gains from turnover of older equipment to current standard equipment and the adoption of high-efficiency equipment due to natural market forces and existing energy efficiency programs. The Static Efficiency case shows what load would be in absence of this naturally occurring energy efficiency.
  - **Base Forecast:** This is the segmented end use forecast developed by ICF and based on the key drivers in the IESO forecast.
  - **DSM25:** This scenario attempts to mimic program intervention that is largely information-based, with financial incentives for measure installation set to 25% of measure incremental cost. ($A \approx 0.25$)
  - **DSM50:** This scenario reflects a fairly common program approach wherein, financial incentives are set equal to approximately 50% of measure incremental cost. In addition, program implementation costs are assumed to be higher due to more intensive marketing and technical assistance efforts. ($A \approx 0.50$)
  - **DSM100:** Here we assume that incentives are equal to 100% of measure incremental costs and program implementation costs are correspondingly higher reflecting intensive recruiting and technical assistance. ($A \approx 0.75$)
  - **DSM100 Plus Standards Scenario:** For this scenario, we assume that Ontario implements a series of aggressive standards starting in 2008 to build upon the rapid market share growth achieved under the DSM100 scenario. Once these standards are implemented, the minimum efficiency equipment that can be bought is the high-efficiency category. At the same time, an emerging technology enters the market at a low initial market share and is gradually accelerated into the market.
- Estimated achievable energy efficiency potential is divided fairly evenly among the residential, commercial, and industrial sectors.
- Lighting, space heating, and industrial processes make up the majority of electricity sales savings potential. Commercial office equipment and air conditioning also contribute significantly to overall savings.
- Peak demand savings potential is dominated by air conditioning and industrial processes, with lighting also playing an important role.

Table 6. Load Forecast Under Achievable Potential Scenarios (Electricity Sales, MWh)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	145,271,108	154,784,424	166,563,340	181,079,862	198,121,155
Base Forecast	143,627,011	149,385,497	155,834,699	163,018,356	170,985,694
DSM25	143,627,011	148,240,144	150,146,510	150,279,326	153,769,936
DSM50	143,627,011	144,409,488	135,398,851	135,787,180	143,293,923
DSM100	143,627,011	138,472,183	127,540,380	132,617,674	142,763,974
DSM100 Plus Standards	143,627,011	122,173,115	123,725,786	132,193,563	142,468,253

Table 7. Load Forecast Under Achievable Potential Scenarios (Peak Demand, MW)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	23,572	26,054	28,896	32,112	35,435
Base Forecast	23,268	24,804	26,430	28,170	30,025
DSM25	23,268	24,604	25,485	26,326	27,749
DSM50	23,268	23,957	23,377	24,133	25,699
DSM100	23,268	23,035	22,138	23,368	25,508
DSM100 Plus Standards	23,268	20,179	21,046	23,120	25,292

Figure 7. Achievable Potential Scenarios – 2005-2025 (Electricity Sales)

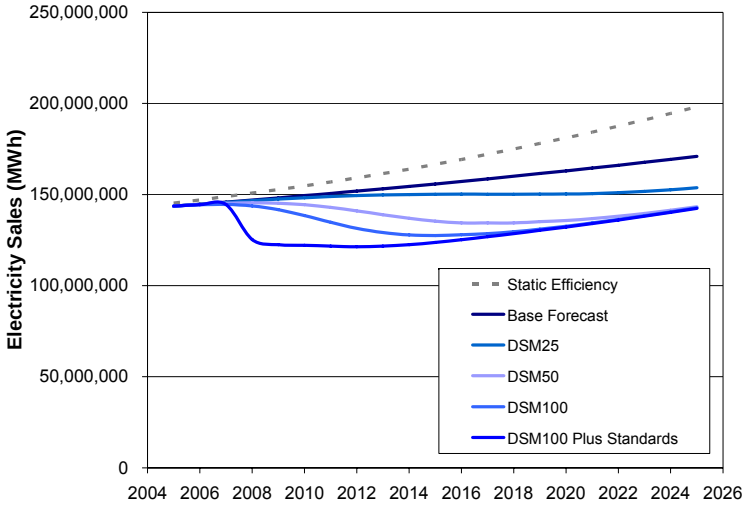


Figure 8. Achievable Potential Scenarios – 2005-2025 (Peak Demand)

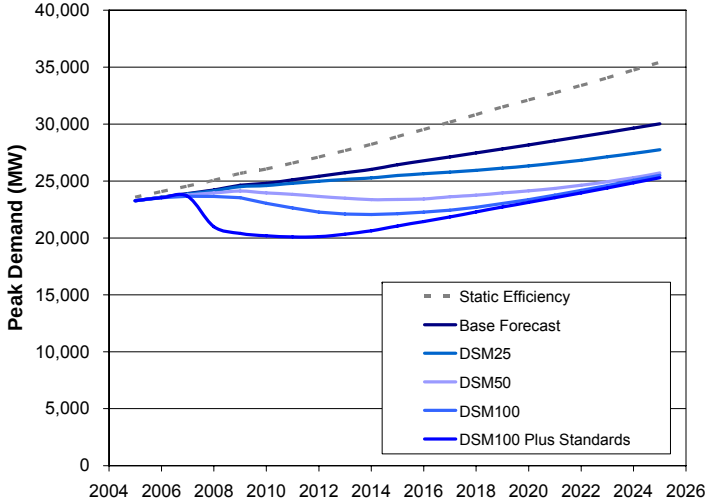


Figure 9. 2015 Achievable Potential by Sector (Electricity Sales)

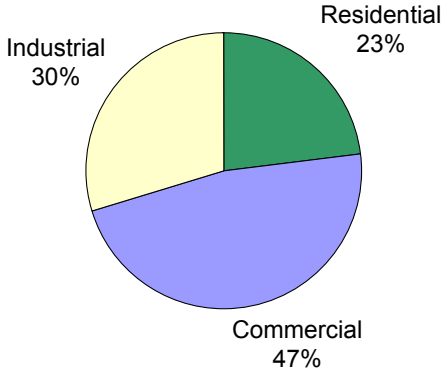


Figure 10. 2015 Achievable Potential by Sector (Peak Demand)

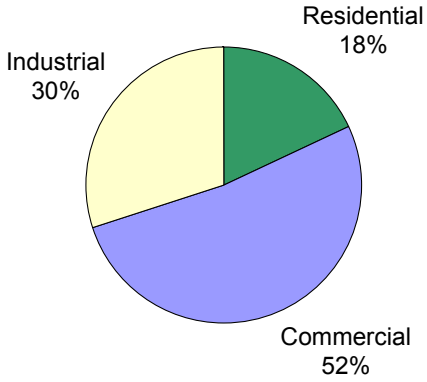


Figure 11. 2015 Achievable Potential by End Use (Electricity Sales)

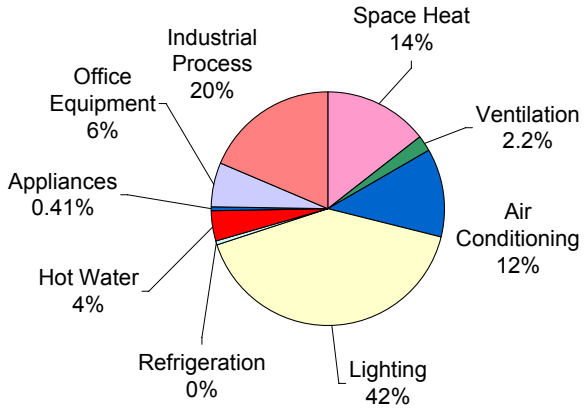


Figure 12. 2015 Achievable Potential by End Use (Peak Demand)

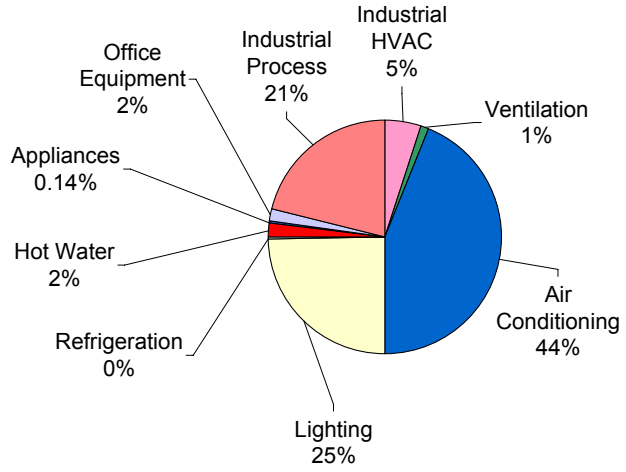


Figure 13. 2015 Achievable Potential by Sector and End Use (Electricity Sales)

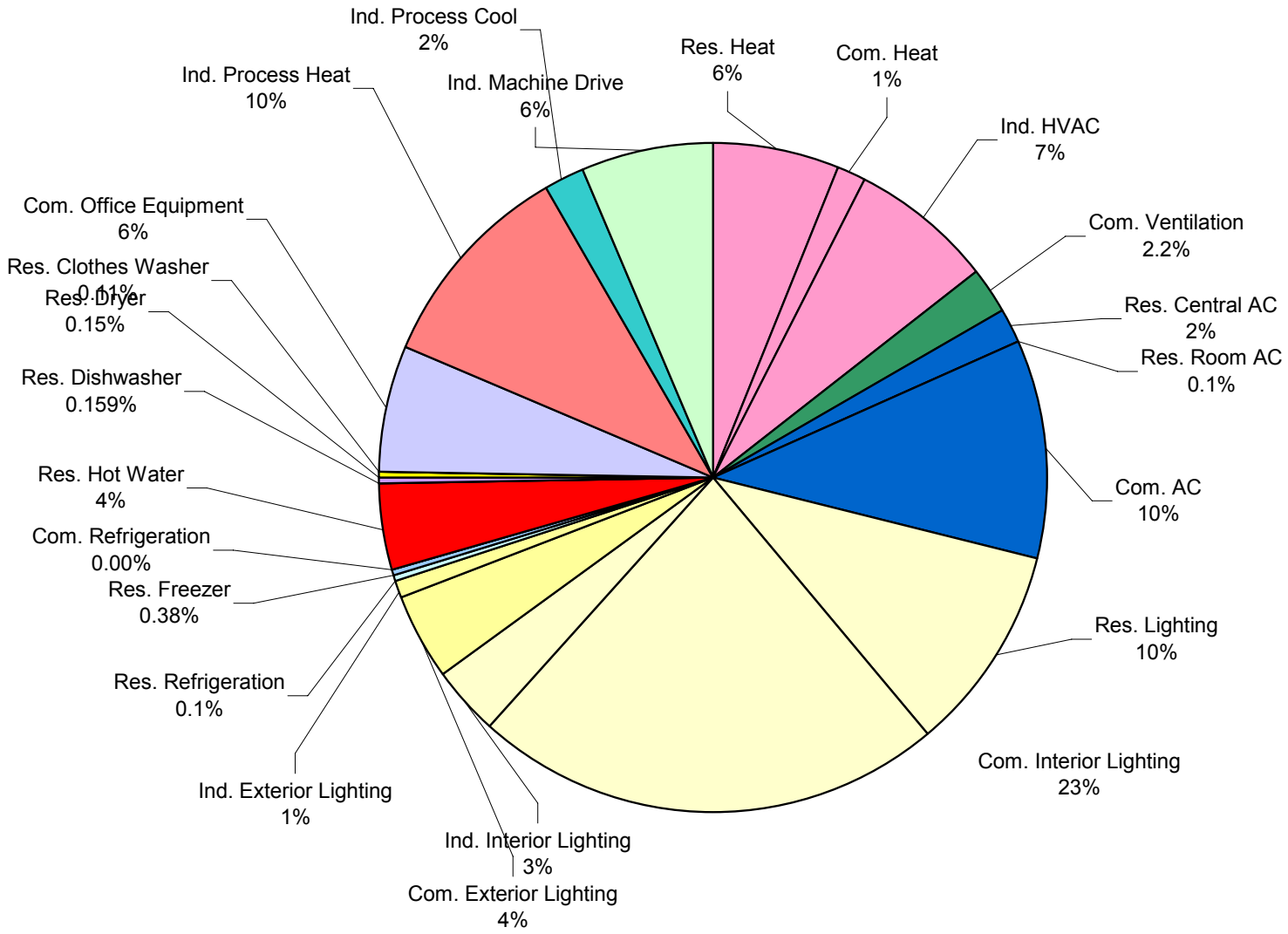
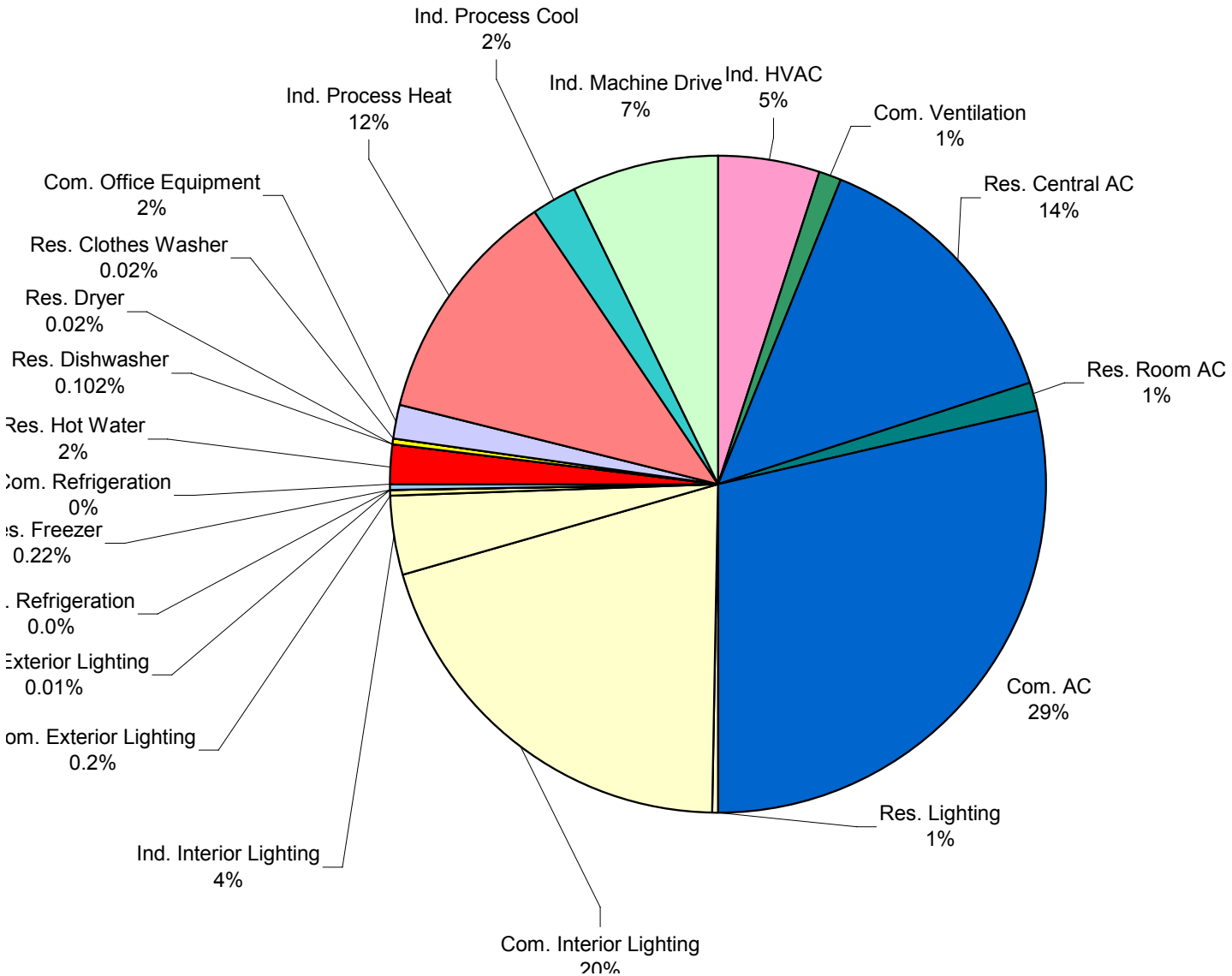


Figure 14. 2015 Achievable Potential by Sector and End Use (Peak Demand)



4.2. Experience-Based Approach

4.2.1. Summary of Other Assessments of Energy Efficiency Potential

- As noted above, we have reviewed approximately twenty assessments of energy efficiency potential and culled from those studies estimates of economic and achievable potential expressed in terms of percentage reductions from baseline sales and/or demand. The following table summarizes the range of results from these studies.

Table 8. Summary of Energy Efficiency Potential Studies

	Technical Potential	Economic Potential	Maximum Achievable Potential	Achievable Potential
Residential Sector	21%–36%	10.6%–30%	11%–35%	5.3%–21.7%
Commercial Sector	18%–41%	12.7%–35%	9%–39%	5.1%–17%
Industrial Sector	17%–38%	6.2%–32%	7%–60%	2%–19%

- These studies employ a variety of methodologies and definitions of different classes of potential are not always consistent. The lower ends of the ranges presented tend to emerge from studies employing more formal accounting models with endogenous energy efficiency measure adoption functions. Thus, adoption is forecast using a general adoption algorithm as is used in this study, or as a function of program cost-effectiveness. The higher ends of the ranges are produced using methods that tend to reply on judgment-based estimates of adoption.
- This variety of definition and approach shows most clearly in estimates of Maximum Achievable Potential. Some studies define this level of potential as that which represents the maximum amount of potential that could reasonably be captured through feasible policies. Other studies define this level in terms of the maximum market share for efficiency measures, taking into account the fact that there will always be some fraction of the market that will not adopt a technology. This latter definition often results in an estimate of potential that closely matches the level of economic potential over time, and will always exceed by a substantial amount an estimate based on the former method.
- For each of the studies identified, we calculated the savings percentage for the residential, commercial, and industrial sectors at five year intervals over the studies' time horizons. These savings percentages were then multiplied by projected baseline electricity sales for the respective years in order to arrive at the electricity usage that would result were the studies' assumptions and methods to be applied to Ontario. These savings estimates were then subtracted from the total baseline electricity to show predicted electricity sales under the extrapolated savings percentages.

- Given the wide range of savings potential estimates, the studies have been classified into two subsets based upon the type of potential estimated.
  - The first subset shows the potential electricity sales for Ontario based on the predicted savings percentages of studies identifying potential savings from **DSM25 to DSM50 programs**. There is significant variance between these studies in part because each study defines a DSM25 or DSM50 program differently. Also, in several cases these studies ignore potential efficiency savings in certain areas of the economy (i.e., residential lighting), or are limited to programs already in existence within the study area, reducing the overall savings identified.
  - The second subset shows the potential electricity sales numbers for Ontario based on the **maximum achievable potential** from instituting a DSM100 program requiring large sustained investment. These studies represent the upper bounds of potential energy efficiency savings.
  - Table 9 illustrates these ranges. The first column shows the reduction in sales, the second column shows the adjusted level of sales after accounting for the reductions and the third shows the relative reduction in sales.
  - Figures 15 and 16 plot the levels of sales that would be observed in Ontario if the relative reductions predicted in the various studies were to be realized in the Province.

Table 9. Overview of Energy Efficiency Potential Studies and Program Experience

		Historical Savings		
		Total Savings Range (GWh)	Net Range (GWh)	% Savings Range
2010	Min	3,401	145,984	2.3%
	Max	4,914	144,471	3.3%
2015	Min	3,559	151,213	2.3%
	Max	11,237	143,535	7.3%
2020	Min	3,748	158,151	2.3%
	Max	18,795	143,104	11.6%
2025	Min	3,959	165,848	2.3%

		DSM50 Achievable		
		Total Savings Range (GWh)	Net Range (GWh)	% Savings Range
2010	Min	3,023	146,363	2.0%
	Max	8,963	140,422	6.0%
2015	Min	6,251	148,521	4.0%
	Max	18,573	136,199	12.0%
2020	Min	9,429	152,470	5.8%
	Max	25,904	135,995	16.0%
2025	Min	12,467	157,340	7.3%

Maximum Achievable Potential

		Total Savings Range (GWh)	Net Range (GWh)	% Savings Range
2010	Min	10,756	138,630	7.2%
	Max	23,638	125,748	15.8%
2015	Min	20,894	133,878	13.5%
	Max	48,227	106,544	31.2%
2020	Min	27,221	134,678	16.8%
	Max	62,243	99,656	38.4%
2025	Min	33,018	136,789	19.4%
	Max	75,492	94,315	44.5%

Figure 15. Predicted Sales from DSM50 Achievable Studies

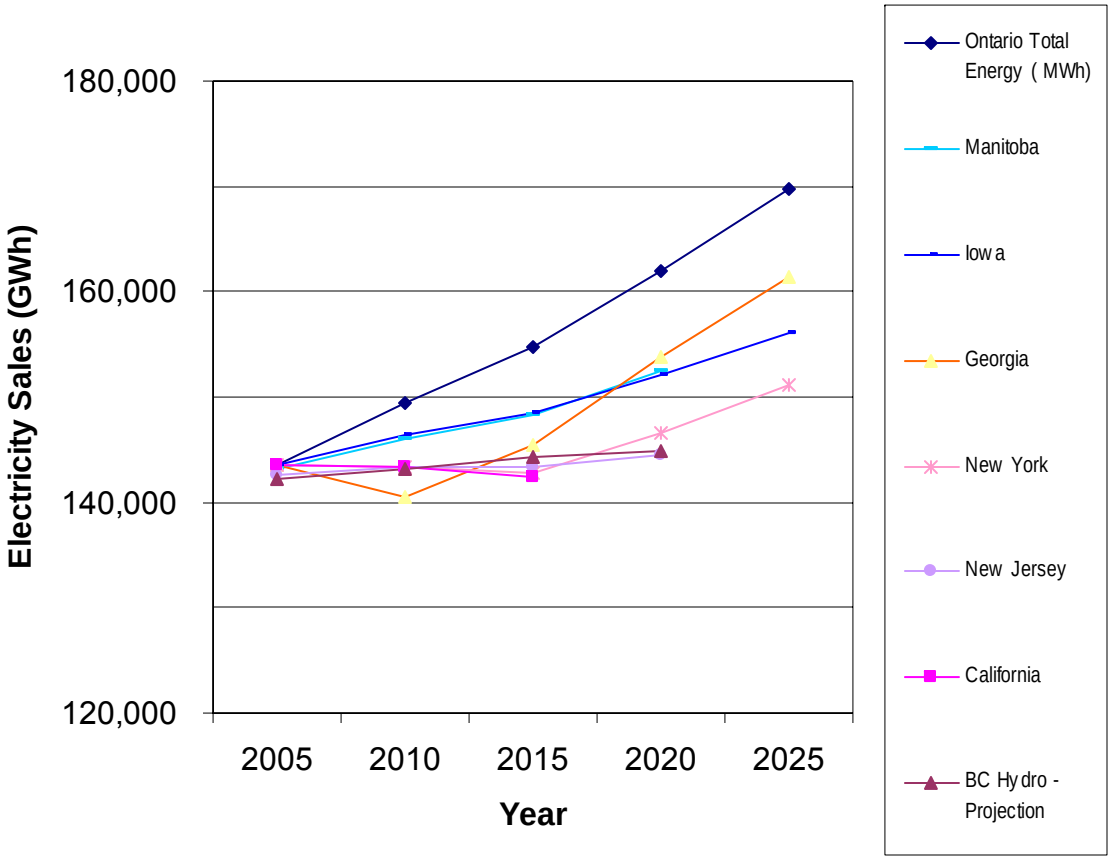
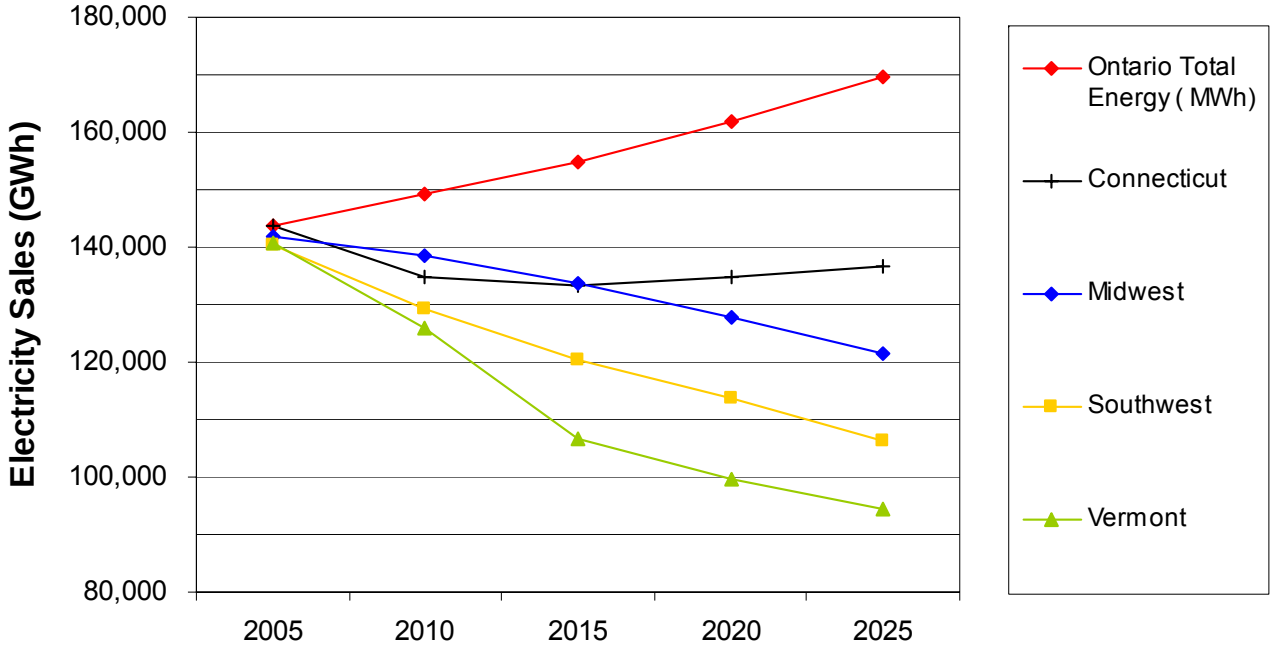


Figure 16. Predicted Sales from Economic Potential Studies



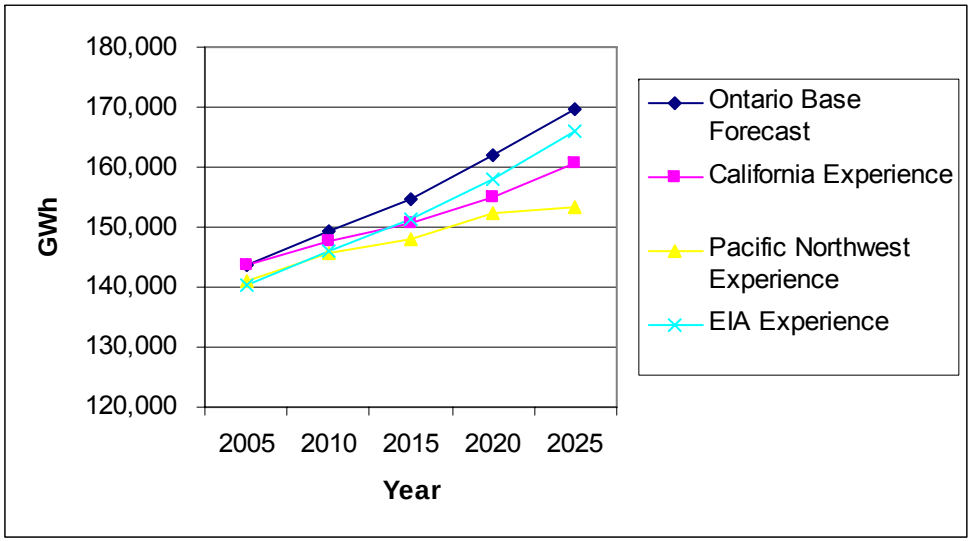
4.2.2. Summary of Program Experience

- As noted earlier, application of the impacts of individual best practice or exemplary programs to the Ontario situation is complicated by the fact that the program results tend to be reported in absolute rather than relative terms. Absent more detailed information regarding the duration of programs, funding profile and base sales and demand, this program experience cannot be applied in a manner that yields much insight in the Ontario context.
- As an alternative, we have gathered time series program impact data from three sources: (1) The Regional Technical Forum (Pacific Northwest); (2) The Energy Information Administration (pertaining to total US utility energy efficiency investment); and (3) The State of California. These impact data allow us to calculate relative reductions in annual sales and demand that can be applied to the forecast of Ontario load to yield a useful illustration of potential impact.
- The figure below illustrates the level of electricity sales in Ontario under scenarios based on these three sources of energy efficiency program experience.
- The Regional Technical Forum (RTF) reports data on annual electricity savings due to utility- or public benefits-funded energy efficiency programs, state building codes and federal appliance standards for the period 1981 through 2004 for the states comprising the Northwest Power Planning Council. The RTF data show actual energy savings growing from about 1.7 percent in 1984 to over 15 percent by 2004. However, 38 percent of the cumulative savings are attributable, according to the RTF, to federal appliance efficiency standards and state building codes. Therefore, we first subtracted the savings attributable to building codes and appliance standards from the results so that we represent only the savings associated with direct financial investment in energy efficiency measures such as would occur under a traditional utility-funded energy efficiency program. These annual savings data were divided by historical annual retail sales for the same jurisdictions to yield percentage reductions in sales by year.
- The RTF data show actual energy savings growing from about 1.7 percent in 1984 to over 15 percent by 2004. These annual savings fractions were laid against our forecast of Ontario baseline sales to yield an estimate of the level of future sales in Ontario under circumstances that yield the same relative levels of savings.
- The EIA data show reported annual electricity savings by all US utilities for the period 1989 through 2003. However, the EIA data show the sometimes pronounced annual fluctuations produced by sudden increases or decreases in program funding. However, over the period covered, annual percentage decreases in electricity sales typically varied between one and two percent. For purposes of this exercise, we selected the maximum annual reduction in sales for each customer class, applied those to our forecast of Ontario class sales and summed the result.
- Similar to the Pacific Northwest, California has a long history of investment in energy efficiency. Data reported by the California Energy Commission show that since 1976, total electricity sales have been reduced by 15 percent relative what they otherwise would have been. Although the pattern of annual savings again shows wide fluctuations based on funding cycles, the California trend has been toward steadily increasing cumulative savings. As is the case with the RTF data, the California savings data include the impacts of state building codes and appliance efficiency standards which together account for almost half of cumulative savings over the period. Again, these savings were

subtracted from the total to enable a more reasonable comparison. For purposes of this exercise, we simply prepared a straight-line interpolation between an assumed savings level of 0 percent in 1976 to 7 percent in 2004. These annual numbers were then applied to the Ontario baseline forecast.

- This exercise highlights several important points. First, the savings realized as the result of typical utility energy efficiency programs generally fall in line with the DSM25 or DSM50 projections of efficiency potential. However, this result is more an artifact of the difficulty in maintaining focus and funding over extended periods of time than it is a reflection of what actually might be achieved. All three time series examined show very pronounced annual variations in savings associated with similarly pronounced funding fluctuations. As will be discussed further below, actually converting the potential we estimate to be achievable into savings achieved will require a consistency in policy and investment that will be unprecedented. Second, although we have netted out the impacts of building codes and appliance standards in our presentation of data above, these policies are extremely important to capturing significant potential over the long run. Unlike conventional financial incentive and technical assistance programs that create transitory market effects, codes and standards lock in efficiency gains. Frequent updating of such standards to reflect improvements in practice and technology such as is done in California, ensures that the net savings associated with codes and standards continue to grow over time. Building codes and standards also tend to be lower cost policies to implement than are incentive programs that often entail significant marketing costs.
- The reported costs for the savings achieved in the Pacific Northwest are $2.6 billion ($2000 US). The real levelized cost for savings acquired has averaged approximately $0.013 (US). The costs reported for the EIA savings data are slightly over $25 billion (US) for the period covered by the savings values, or approximately $0.04 (nominal US). Energy efficiency program spending data for California are incomplete. However, we estimate conservatively that, since 1975, approximately $5 billion (US) have been spent, though the program composition has shifted markedly from largely informational programs in the late 1970s to most rebate programs today. Since 1998, the average levelized cost of a conserved kWh has been slightly above $0.02 (US).

Figure 17. Ontario Electricity Sales Scenarios Based on Program Experience



4.2.3. Comparison with the Results from the Accounting Approach

- The figures below show the results of the accounting model approach in the context of the results implied by other energy efficiency potential studies and historical program impacts. In general, the results of our EEPM analysis are consistent with the magnitude of savings projected or achieved in other contexts. Figure 18 compares the Ontario base forecast and the results from the EEPM-generated DSM25 and DSM50 scenarios with the results from DSM50 scenarios from other efficiency potential studies. Figure 19 compares our estimates with an extension of the Pacific NW, California and EIA historical impact time series to Ontario. For purposes of comparison we present two scenarios based on the Pacific NW data; the first excludes the relative impact of codes and standards and the second includes the impacts of these policies.
- The results for all of the scenarios save for the DSM25 case show the achievable potential for energy efficiency gains to be greater in relative terms than that estimated by other studies. This result holds when we compare our results to the hypothesized effects of applying historical savings.
- Our results, particularly evident in the DSM50 and DSM100 cases, also show a much different savings trajectory than do those of other studies. These results reflect that absolute savings potential is more-or-less fixed and that all scenarios will converge toward this number. The more aggressive scenarios capture a much larger share of this potential in early years, but over an extended horizon, the system would naturally acquire a large fraction of these savings as well. Most other analyses of potential do not account explicitly for this convergence and thus implicitly

assume that savings achievable through policy interventions can continue to grow in relative terms or can maintain a constant relative improvement over what might have otherwise happened in the market.

Figure 18. Comparison of Ontario Estimates of Potential with Other Studies

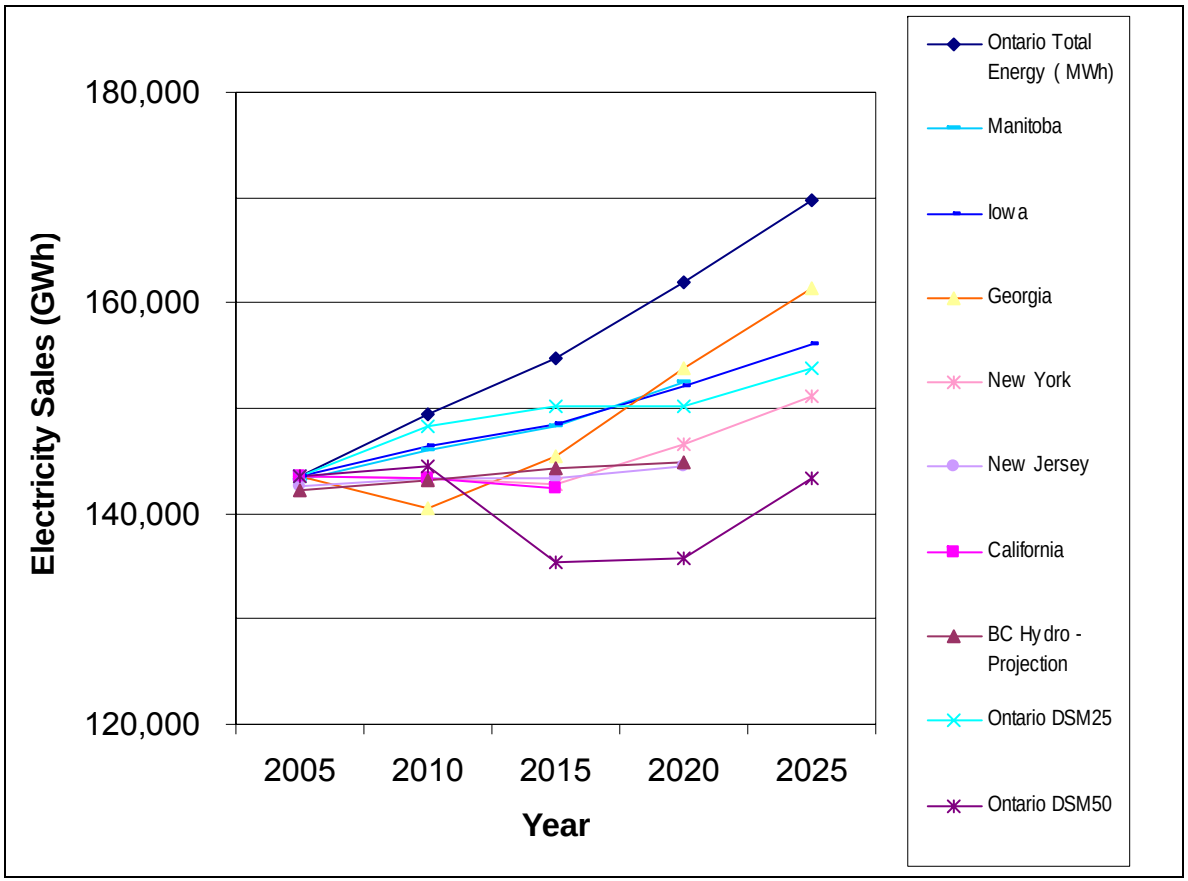
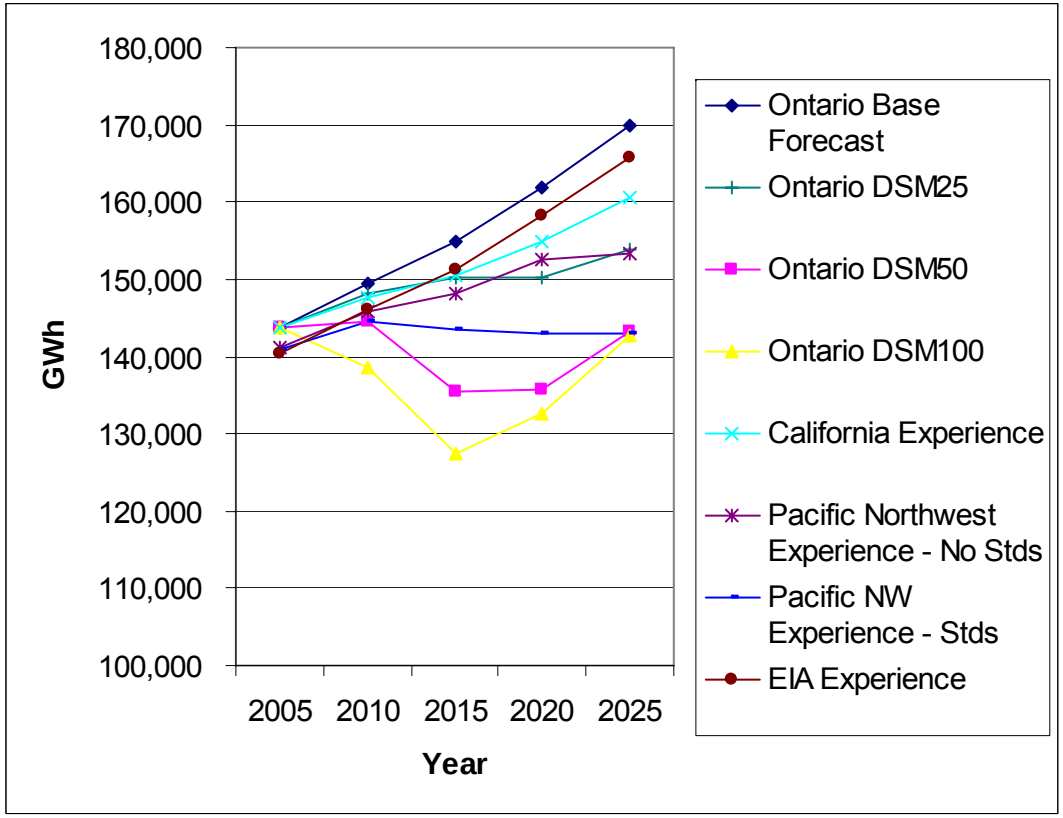


Figure 19. Comparison of Projections of Ontario Potential with Experience



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5. Appendix: Detailed Accounting Model Outputs

Table 10. Electric Base Forecasts and Achievable Potential Scenarios

Electric Base Forecast and Decrements - All Sectors

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	145,271,108	147,087,212	148,916,815	150,789,433	152,740,282	154,784,424	156,926,718	159,171,753	161,523,715	163,986,246	166,563,340	169,257,020	172,068,703	174,997,495	178,045,208	181,079,862	184,239,113	187,522,625	190,929,690	194,464,646	198,121,459
Base Forecast	143,627,011	144,725,376	145,850,102	147,001,491	148,179,850	149,385,497	150,618,756	151,879,961	153,169,451	154,487,578	155,834,699	157,211,181	158,617,398	160,053,736	161,520,588	163,018,356	164,547,453	166,108,299	167,701,326	169,326,974	170,985,694
DSM25	143,627,011	144,672,712	145,674,723	146,616,999	147,478,921	148,240,144	148,882,428	149,393,010	149,766,178	150,007,042	150,146,510	150,190,940	150,181,781	150,165,932	150,200,341	150,279,326	150,525,266	151,000,704	151,744,974	152,604,390	153,769,936
DSM50	143,627,011	144,547,982	145,210,503	145,493,802	145,259,822	144,409,488	142,956,518	141,024,939	138,899,697	136,970,623	135,398,851	134,433,713	134,404,245	134,415,224	135,063,271	135,787,180	136,819,569	138,077,302	139,573,508	141,326,502	143,293,923
DSM100	143,627,011	144,392,700	144,549,232	143,735,708	141,680,303	138,472,183	134,798,999	131,433,589	129,154,276	127,849,620	127,540,380	127,931,637	128,579,067	129,596,991	131,004,459	132,617,674	134,424,818	136,358,547	138,398,610	140,545,195	142,763,974
DSM100 Plus Standards	143,627,011	144,392,700	144,549,232	125,318,350	122,489,942	122,173,115	121,645,720	121,347,137	121,623,248	122,471,377	123,725,786	125,217,063	126,848,258	128,577,402	130,389,228	132,193,563	134,076,911	136,036,116	138,106,746	140,253,263	142,468,253
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	23,572	24,068	24,555	25,062	25,668	26,054	26,573	27,104	27,661	28,217	28,896	29,520	30,163	30,823	31,500	32,112	32,743	33,392	34,057	34,739	35,435
Base Forecast	23,268	23,583	23,889	24,210	24,623	24,804	25,106	25,409	25,723	26,022	26,430	26,769	27,113	27,461	27,813	28,170	28,531	28,898	29,269	29,644	30,025
DSM25	23,268	23,574	23,858	24,143	24,500	24,604	24,804	24,979	25,141	25,267	25,485	25,628	25,776	25,941	26,132	26,326	26,555	26,823	27,130	27,417	27,749
DSM50	23,268	23,552	23,777	23,949	24,117	23,957	23,828	23,646	23,479	23,361	23,377	23,423	23,614	23,758	23,957	24,133	24,351	24,619	24,935	25,297	25,699
DSM100	23,268	23,525	23,664	23,652	23,530	23,035	22,639	22,277	22,095	22,047	22,138	22,269	22,435	22,680	23,020	23,368	23,758	24,173	24,605	25,051	25,508
DSM100 Plus Standards	23,268	23,525	23,664	20,993	20,395	20,179	20,084	20,108	20,330	20,626	21,046	21,439	21,853	22,281	22,721	23,120	23,532	23,955	24,392	24,838	25,292

Residential Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	42,426,726	42,390,412	42,369,095	42,363,295	42,373,479	42,400,027	42,443,192	42,503,067	42,579,532	42,672,222	42,781,492	42,906,181	43,045,028	43,195,004	43,356,333	43,459,854	43,575,227	43,700,944	43,835,558	43,983,139	44,137,951
Base Forecast	42,230,046	41,986,136	41,747,592	41,514,356	41,286,371	41,063,583	40,845,936	40,633,378	40,425,857	40,223,323	40,025,725	39,833,017	39,645,149	39,462,077	39,283,756	39,110,141	38,941,189	38,776,860	38,617,111	38,461,904	38,311,200
DSM25	42,230,046	41,973,847	41,707,295	41,426,433	41,127,015	40,804,851	40,455,433	40,076,034	39,665,414	39,226,113	38,778,573	38,310,493	37,836,338	37,367,379	36,916,144	36,451,021	36,018,940	35,627,574	35,284,275	35,000,055	34,775,248
DSM50	42,230,046	41,944,914	41,601,236	41,169,599	40,617,147	39,918,250	39,084,821	38,136,890	37,141,872	36,180,448	35,334,935	34,672,079	34,216,063	33,920,501	33,775,423	33,660,992	33,582,719	33,531,044	33,498,980	33,500,137	33,515,867
DSM100	42,230,046	41,909,099	41,450,116	40,761,154	39,780,212	38,506,308	37,091,972	35,764,395	34,688,697	34,030,794	33,717,519	33,555,647	33,445,189	33,371,166	33,333,132	33,275,045	33,239,141	33,220,694	33,228,598	33,274,697	33,328,694
DSM100 Plus Standards	42,230,046	41,909,099	41,450,116	38,654,795	37,289,590	36,623,395	35,776,790	34,871,767	34,140,946	33,673,564	33,424,803	33,298,067	33,229,483	33,190,598	33,171,674	33,124,250	33,093,127	33,076,434	33,110,213	33,156,492	33,210,285
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	5,886	5,966	6,044	6,126	6,230	6,280	6,359	6,438	6,521	6,601	6,705	6,793	6,882	6,972	7,060	7,088	7,117	7,146	7,174	7,202	7,228
Base Forecast	5,801	5,796	5,787	5,781	5,796	5,755	5,742	5,727	5,715	5,699	5,705	5,695	5,685	5,675	5,665	5,656	5,646	5,636	5,627	5,617	5,608
DSM25	5,801	5,794	5,781	5,768	5,771	5,715	5,681	5,641	5,599	5,550	5,523	5,482	5,447	5,422	5,410	5,390	5,380	5,379	5,385	5,394	5,406
DSM50	5,801	5,789	5,765	5,728	5,691	5,576	5,471	5,356	5,253	5,173	5,149	5,141	5,153	5,159	5,159	5,114	5,078	5,060	5,055	5,058	5,066
DSM100	5,801	5,784	5,741	5,664	5,560	5,368	5,207	5,086	5,010	4,988	4,973	4,937	4,909	4,903	4,931	4,932	4,939	4,948	4,959	4,973	4,986
DSM100 Plus Standards	5,801	5,784	5,741	5,353	5,114	4,849	4,647	4,522	4,522	4,549	4,599	4,642	4,686	4,731	4,777	4,784	4,793	4,802	4,815	4,828	4,840

Commercial Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	55,763,906	56,940,468	58,096,990	59,272,797	60,489,711	61,757,304	63,079,056	64,458,497	65,899,149	67,404,466	68,977,769	70,622,176	72,340,537	74,135,373	76,008,823	77,919,126	79,914,300	81,995,821	84,164,605	86,420,944	88,764,435
Base Forecast	54,554,001	55,409,577	56,281,092	57,168,852	58,073,169	58,994,361	59,932,754	60,888,678	61,862,471	62,854,477	63,865,048	64,894,541	65,943,321	67,011,761	68,100,239	69,209,143	70,338,868	71,489,815	72,662,396	73,857,028	75,074,139
DSM25	54,554,001	55,387,973	56,208,066	57,007,902	57,777,111	58,504,819	59,180,962	59,796,814	60,346,251	60,827,053	61,242,101	61,600,409	61,917,966	62,218,252	62,532,008	62,876,754	63,306,550	63,858,599	64,562,226	65,229,636	66,055,392
DSM50	54,554,001	55,336,661	56,013,699	56,533,894	56,828,495	56,839,183	56,547,519	56,000,650	55,329,084	54,731,548	54,187,319	54,010,062	54,328,679	54,554,734	55,157,929	55,820,156	56,623,879	57,523,831	58,537,897	59,681,700	60,951,414
DSM100	54,554,001	55,272,569	55,735,080	55,784,536	55,265,775	54,187,482	52,856,222	51,516,169	50,755,849	50,349,174	50,476,522	50,973,861	51,567,940	52,310,152	53,234,751	54,284,338	55,443,009	56,676,822	57,969,876	59,316,083	60,713,279
DSM100 Plus Standards	54,554,001	55,272,569	55,735,080	46,505,672	45,168,831	45,517,058	45,847,227	46,308,165	46,961,484	47,772,806	48,688,731	49,674,941	50,715,189	51,802,921	52,935,884	54,085,177	55,282,451	56,527,761	57,821,541	59,166,800	60,561,021
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	9,997	10,267	10,532	10,807	11,129	11,358	11,649	11,949	12,264	12,583	12,962	13,321	13,692	14,077	14,475	14,867	15,273	15,693	16,126	16,571	17,028
Base Forecast	9,815	10,017	10,218	10,427	10,677	10,828	11,033	11,240	11,454	11,662	11,921	12,151	12,385	12,622	12,863	13,108	13,356	13,609	13,866	14,127	14,391
DSM25	9,815	10,013	10,203	10,393	10,615	10,727	10,880	11,021	11,156	11,274	11,431	11,554	11,679	11,810	11,953	12,104	12,272	12,462	12,676	12,852	13,058
DSM50	9,815	10,002	10,163	10,297	10,426	10,408	10,399	10,365	10,336	10,329	10,341	10,391	10,530	10,634	10,785	10,956	11,139	11,339	11,560	11,803	12,070
DSM100	9,815	9,989	10,107	10,153	10,144	9,970	9,840	9,675	9,614	9,613	9,706	9,840	9,989	10,165	10,376	10,607	10,860	11,129	11,408	11,696	11,992
DSM100 Plus Standards	9,815	9,989	10,107	8,834	8,477	8,536	8,627	8,739	8,890	9,068	9,303	9,531	9,771	10,020	10,278	10,533	10,797	11,068	11,347	11,634	11,928

Industrial Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	47,080,476	47,756,332	48,450,730	49,153,341	49,877,092	50,627,093	51,404,469	52,210,190	53,045,034	53,909,558	54,804,079	55,728,663	56,683,138	57,667,119	58,680,052	59,700,881	60,749,586	61,825,860	62,929,527	64,060,564	65,219,073
Base Forecast	46,842,965	47,329,663	47,821,418	48,318,283	48,820,310	49,327,553	49,840,066	50,357,904	50,881,123	51,409,778	51,943,926	52,483,623	53,028,928	53,579,898	54,136,594	54,699,073	55,267,396	55,841,624	56,421,819	57,008,042	57,600,355
DSM25	46,842,965	47,310,892	47,759,361	48,182,664	48,574,795	48,930,473	49,246,033	49,520,162	49,754,513	49,953,876	50,125,836	50,280,037	50,427,477	50,580,301	50,752,189	50,951,550	51,199,777	51,514,531	51,898,472	52,374,699	52,939,297
DSM50	46,842,965	47,266,407	47,595,568	47,790,308	47,814,180	47,652,055	47,324,178	46,887,400	46,428,741	46,058,627	45,876,596	45,751,572	45,859,503	45,939,989	46,129,918	46,306,032	46,612,971	47,022,427	47,536,631	48,144,665	48,826,641
DSM100	46,842,965	47,211,032	47,364,036	47,190,018	46,634,316	45,778,394	44,850,805	44,153,025	43,709,730	43,469,652	43,346,340	43,402,129	43,565,939	43,915,673	44,436,575	45,058,292	45,742,669	46,461,030	47,200,136	47,954,415	48,722,002
DSM100 Plus Standards	46,842,965	47,211,032	47,364,036	40,157,883	40,031,522	40,032,662	40,021,702	40,167,205	40,520,818	41,025,006	41,612,253	42,244,055	42,903,587	43,583,883	44,281,669	44,984,137	45,701,333	46,431,921	47,174,991	47,929,971	48,696,946
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	7,689	7,835	7,979	8,128	8,309	8,415	8,564	8,717	8,876	9,033	9,230	9,407	9,588	9,774	9,965	10,157	10,353	10,553	10,758	10,967	11,180
Base Forecast	7,652	7,769	7,883	8,002	8,150	8,221	8,331	8,441	8,554	8,661	8,804	8,923	9,043	9,163	9,285	9,407	9,529	9,652	9,776	9,901	10,026
DSM25	7,652	7,767	7,874	7,982	8,114	8,162	8,243	8,316	8,386	8,444	8,531	8,592	8,650	8,709	8,769	8,833	8,903	8,981	9,069	9,170	9,285
DSM50	7,652	7,760	7,850	7,924	8,000	7,972	7,958	7,925	7,891	7,860	7,887	7,891	7,931	7,964	8,012	8,063	8,133	8,219	8,321	8,436	8,563
DSM100	7,652	7,752	7,816	7,835	7,826	7,696	7,592	7,516	7,471	7,446	7,460	7,491	7,538	7,612	7,712	7,829	7,959	8,096	8,237	8,382	8,530
DSM100 Plus Standards	7,652	7,752	7,816	6,806	6,804	6,794	6,810	6,847	6,918	7,010	7,143	7,267	7,396	7,529	7,666	7,803	7,943	8,086	8,230	8,376	8,524

Figure 20. Residential Sector Achievable Potential Scenarios (Electricity Sales)

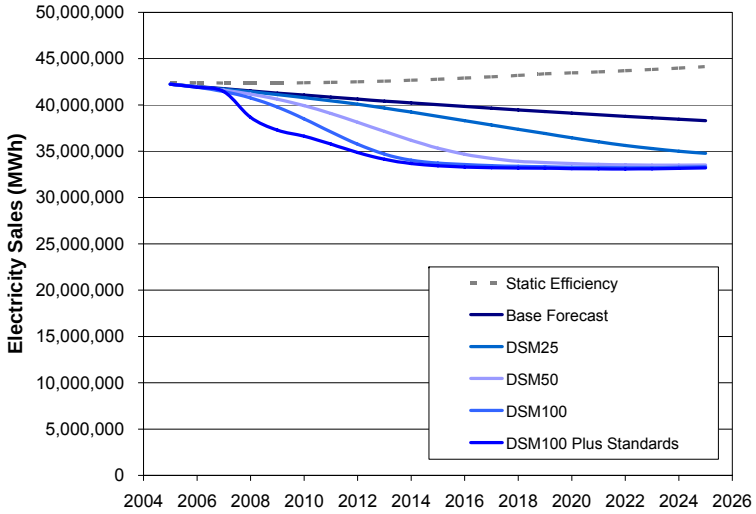

Figure 21. Residential Sector Achievable Potential Scenarios (Peak Demand)

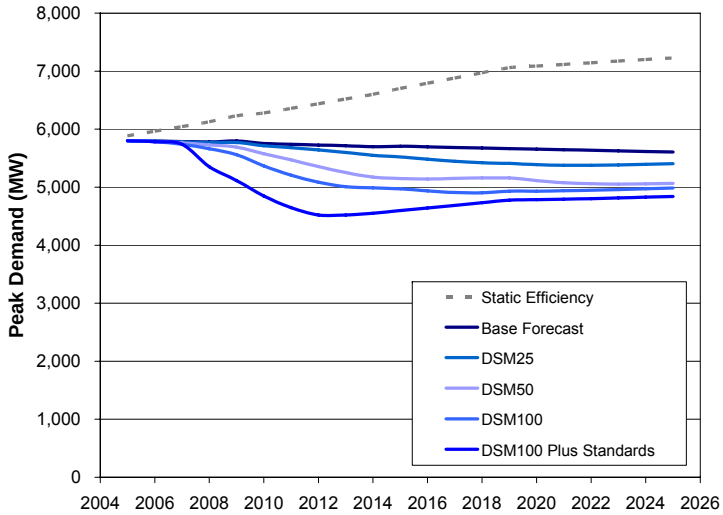

Figure 22. 2015 Residential Sector Achievable Potential by End Use (DSM50, Electricity Sales)

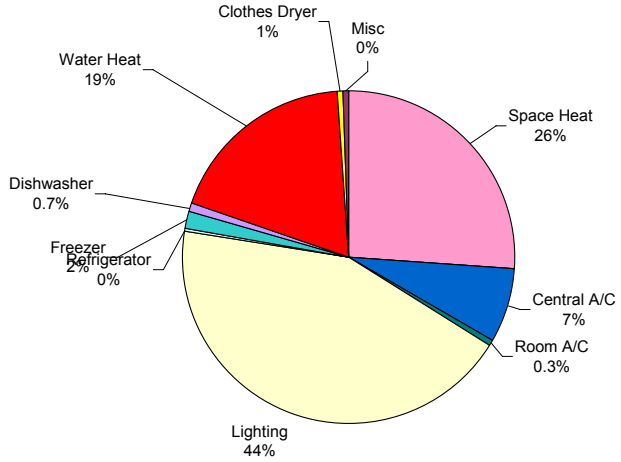

Figure 23. 2015 Residential Sector Achievable Potential by End Use (DSM50, Peak Demand)

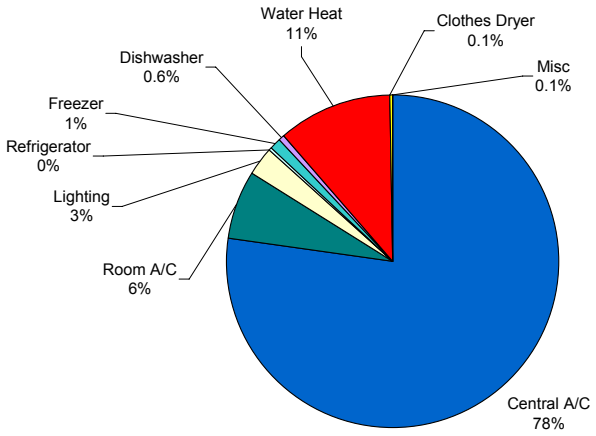

Table 11. Residential Sector Results by End Use

DSM25 Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	4,029	13,341	29,346	53,537	87,355	131,966	187,968	255,034	331,569	414,471	499,147	579,870	650,502	705,440	741,030	754,966	747,496	720,841	678,587	624,953
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	1,012	3,404	7,610	14,104	23,356	35,754	51,491	70,417	91,880	114,599	136,626	155,493	168,571	173,618	181,662	182,484	176,902	166,336	152,390	136,528
Room A/C	-	80	265	580	1,049	1,689	2,502	3,470	4,543	5,635	6,632	7,398	7,809	7,775	7,269	6,946	6,371	5,643	4,853	4,069	3,335
Lighting	-	1,958	6,653	15,085	28,533	48,599	77,255	116,880	170,254	240,495	330,896	444,617	584,176	750,732	943,186	1,157,245	1,384,758	1,613,724	1,829,381	2,016,493	2,162,358
Refrigerator	-	599	1,632	2,913	4,249	5,465	6,415	6,999	7,156	6,868	(7,509)	(18,517)	(25,859)	(29,272)	(28,558)	(6,527)	18,030	44,995	74,120	100,608	127,970
Freezer	-	71	180	299	409	494	1,467	3,807	7,694	13,299	19,912	27,787	36,942	47,314	58,756	71,044	83,896	96,992	110,006	122,623	134,560
Dishwasher	-	10	28	50	72	91	104	108	104	90	67	3,901	8,307	13,414	18,689	23,836	28,529	32,478	35,497	37,554	38,765
Water Heat	-	4,354	14,321	31,197	56,167	90,067	133,087	184,419	241,934	302,000	359,592	408,823	443,909	460,388	456,198	442,588	413,232	372,141	323,890	272,737	222,112
Clothes Dryer	-	41	108	189	271	346	406	500	1,121	2,344	4,243	6,879	10,297	14,456	19,122	24,239	29,723	35,465	41,342	47,226	52,992
Misc	-	134	364	653	965	1,270	1,546	1,703	2,188	3,029	4,250	5,862	7,867	10,816	13,892	17,056	20,260	23,450	26,569	29,561	32,378
Total	-	12,289	40,297	87,923	159,357	258,732	390,503	557,344	760,443	997,210	1,247,153	1,522,523	1,808,812	2,094,698	2,367,612	2,659,119	2,922,250	3,149,286	3,332,836	3,461,849	3,535,952
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	1.3	4.3	9.5	17.4	28.7	43.6	62.4	85.0	110.4	137.1	162.4	183.1	195.4	196.2	203.3	201.3	191.6	176.3	157.4	137.0
Room A/C	-	0.2	0.6	1.4	2.5	4.1	6.0	8.2	10.7	13.2	15.5	17.2	18.0	17.9	16.7	15.8	14.3	12.5	10.6	8.7	7.0
Lighting	-	0.0	0.1	0.1	0.2	0.4	0.6	0.9	1.4	1.9	2.6	3.5	4.6	5.9	7.4	9.0	10.7	12.5	14.0	15.4	16.3
Refrigerator	-	0.1	0.2	0.3	0.4	0.6	0.6	0.7	0.7	0.7	(0.8)	(2.1)	(3.0)	(3.5)	(3.6)	(1.6)	0.6	3.1	5.7	8.1	10.6
Freezer	-	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.6	1.0	1.6	2.3	3.1	4.0	5.0	6.1	7.2	8.3	9.5	10.5	11.6
Dishwasher	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.8	1.3	1.8	2.3	2.7	3.0	3.3	3.5	3.6
Water Heat	-	0.3	1.1	2.3	4.1	6.6	9.7	13.4	17.4	21.6	25.7	29.0	31.3	32.2	31.6	30.3	27.9	24.7	21.1	17.4	13.7
Clothes Dryer	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1
Misc	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.6	0.6	0.7
Total	-	1.9	6.2	13.6	24.8	40.3	60.7	86.0	115.9	148.9	181.8	213.0	238.3	253.6	255.6	265.9	265.8	257.0	241.9	222.7	201.6

DSM50 Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	13,617	48,931	116,072	225,062	380,812	576,258	788,667	985,258	1,136,979	1,230,048	1,266,997	1,265,679	1,265,891	1,223,180	1,164,463	1,107,461	1,049,781	988,633	922,609	852,429
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	3,420	12,530	30,350	60,188	104,265	161,328	224,422	281,637	321,328	338,059	333,755	320,582	310,690	303,643	315,939	324,326	324,266	318,377	308,520	296,524
Room A/C	-	271	965	2,260	4,287	7,011	10,110	12,993	15,051	15,965	15,779	17,310	15,937	14,764	13,732	13,736	13,573	13,221	12,743	12,230	11,748
Lighting	-	6,679	25,011	62,890	132,344	250,550	439,339	720,533	1,103,843	1,568,281	2,050,835	2,465,299	2,750,078	2,900,532	2,953,661	2,951,829	2,923,023	2,880,801	2,830,449	2,773,637	2,710,690
Refrigerator	-	1,808	4,827	8,296	11,524	14,028	1,568	(5,176)	(4,842)	3,493	19,841	43,145	71,615	103,287	136,472	184,208	230,090	273,711	314,867	349,609	381,328
Freezer	-	202	486	764	1,870	5,622	12,766	23,839	38,908	57,473	77,959	99,450	121,034	142,017	161,917	180,423	197,343	212,562	226,017	228,559	229,673
Dishwasher	-	32	86	148	203	243	4,276	10,021	17,313	25,274	32,408	37,381	39,904	40,909	41,058	40,926	40,730	40,524	40,320	40,118	39,917
Water Heat	-	14,685	52,206	121,750	230,294	376,547	544,410	703,017	819,205	875,014	873,858	831,782	764,265	669,043	566,485	476,573	388,975	307,128	233,081	167,182	108,874
Clothes Dryer	-	119	302	501	725	1,969	4,535	8,650	14,366	21,515	29,765	38,733	48,076	57,485	66,560	75,175	83,246	90,719	97,559	103,744	109,259
Misc	-	389	1,014	1,726	2,726	4,285	6,527	9,523	13,245	17,553	22,238	27,085	31,916	36,959	41,624	45,877	49,703	53,104	56,086	55,559	54,890
Total	-	41,221	146,356	344,757	669,224	1,145,333	1,761,115	2,496,488	3,283,985	4,042,875	4,690,790	5,160,938	5,429,087	5,541,576	5,508,332	5,449,149	5,358,470	5,245,816	5,118,132	4,961,767	4,795,333
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	4.3	15.7	37.9	75.3	130.2	201.8	281.8	355.4	407.1	429.4	421.5	400.9	388.1	381.9	416.8	444.5	453.8	451.3	441.1	427.0
Room A/C	-	0.7	2.3	5.4	10.3	16.7	23.9	30.4	34.8	36.6	35.9	37.8	34.5	31.5	28.8	28.0	27.0	25.6	24.0	22.4	20.9
Lighting	-	0.1	0.2	0.5	1.1	2.0	3.6	5.8	8.9	12.5	16.3	19.5	21.7	22.7	23.0	22.8	22.5	22.0	21.5	20.9	20.3
Refrigerator	-	0.2	0.5	0.8	1.2	1.4	(0.1)	(1.0)	(1.2)	(0.7)	0.8	2.9	5.4	8.2	11.2	15.6	19.8	23.8	27.6	30.7	33.6
Freezer	-	0.0	0.0	0.1	0.2	0.4	1.0	1.9	3.2	4.8	6.7	8.6	10.5	12.3	14.1	15.7	17.1	18.4	19.6	19.7	19.6
Dishwasher	-	0.0	0.0	0.0	0.0	0.0	0.4	1.0	1.7	2.4	3.1	3.6	3.8	3.9	3.9	3.8	3.8	3.8	3.7	3.7	3.6
Water Heat	-	1.1	3.9	9.0	17.0	27.6	39.6	50.8	58.9	62.4	62.0	58.6	53.8	47.5	41.1	35.8	30.6	25.7	21.0	16.7	12.7
Clothes Dryer	-	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0	2.1	2.2	2.3
Misc	-	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.2	1.2	1.2
Total	-	6.3	22.7	53.9	105.1	178.5	270.4	371.1	462.3	526.0	555.4	553.9	532.3	516.3	506.3	541.2	568.2	576.2	572.0	558.7	541.3

Residential Sector Results by End Use *(continued)*

DSM100 Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	25,620	100,057	252,370	496,612	799,692	1,085,367	1,290,430	1,419,343	1,527,560	1,524,864	1,484,871	1,445,082	1,397,606	1,338,315	1,269,538	1,193,522	1,113,339	1,031,264	948,994	867,897
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	6,442	25,769	67,024	136,948	228,824	317,900	379,042	405,426	404,912	410,349	419,873	426,233	421,870	403,893	397,098	387,149	375,802	363,862	351,753	339,780
Room A/C	-	507	1,953	4,794	9,024	13,675	17,328	19,267	24,489	23,342	22,457	21,601	20,482	19,038	17,415	16,740	16,048	15,384	14,773	14,232	13,770
Lighting	-	12,713	53,132	150,241	353,787	728,542	1,305,194	1,989,101	2,569,115	2,910,521	3,050,429	3,084,292	3,074,862	3,048,792	3,015,121	2,976,455	2,933,325	2,885,621	2,833,030	2,775,177	2,711,670
Refrigerator	-	3,004	7,716	12,602	2,550	1,209	11,492	33,844	65,421	102,037	140,323	178,285	214,944	249,882	282,955	327,949	369,915	408,951	445,164	451,426	456,023
Freezer	-	317	722	1,943	7,301	18,338	35,395	57,135	81,492	106,751	131,289	154,597	176,391	196,533	214,951	231,611	246,493	259,592	261,799	262,615	262,067
Dishwasher	-	54	141	230	300	4,386	11,532	21,556	31,784	38,609	41,304	41,744	41,496	41,323	41,118	40,911	40,706	40,501	40,298	40,096	39,894
Water Heat	-	27,570	105,986	260,357	491,904	747,446	943,666	1,038,911	1,085,341	1,008,549	901,606	791,646	685,728	587,216	495,359	421,526	350,920	283,368	219,245	159,158	103,766
Clothes Dryer	-	190	459	752	2,638	6,733	13,203	21,566	31,046	40,990	50,992	60,839	70,427	79,661	88,303	96,330	103,727	110,482	116,586	122,031	126,812
Misc	-	622	1,542	2,889	5,096	8,429	12,886	18,130	23,705	29,258	34,593	39,621	44,315	48,991	53,194	56,939	60,244	63,126	62,493	61,726	60,827
Total	-	77,037	297,476	753,202	1,506,159	2,557,275	3,753,964	4,868,983	5,737,160	6,192,529	6,308,207	6,277,369	6,199,961	6,090,912	5,950,623	5,835,096	5,702,048	5,556,166	5,388,513	5,187,207	4,982,506
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	8.2	32.5	84.4	173.5	291.8	410.3	496.3	537.3	541.6	563.5	592.2	615.2	615.8	584.2	575.8	561.6	545.2	528.3	511.4	495.1
Room A/C	-	1.2	4.7	11.5	21.6	32.3	40.4	44.3	53.1	50.1	47.9	45.6	42.6	39.1	35.2	33.1	31.0	29.0	27.1	25.4	23.9
Lighting	-	0.1	0.4	1.2	2.9	5.9	10.6	16.0	20.6	23.2	24.2	24.4	24.2	23.8	23.4	23.0	22.5	22.0	21.5	20.9	20.3
Refrigerator	-	0.3	0.8	1.3	0.3	(0.4)	0.3	2.2	5.0	8.2	12.0	15.4	18.7	21.9	24.8	29.0	32.8	36.4	39.7	39.9	40.0
Freezer	-	0.0	0.1	0.2	0.7	1.5	3.0	4.9	7.0	9.2	11.5	13.5	15.4	17.2	18.8	20.2	21.5	22.6	22.7	22.6	22.4
Dishwasher	-	0.0	0.0	0.0	0.0	0.4	1.1	2.1	3.1	3.7	4.0	4.0	3.9	3.9	3.9	3.8	3.8	3.7	3.7	3.7	3.6
Water Heat	-	2.0	7.8	19.2	36.3	54.7	68.6	75.0	78.2	73.2	67.0	60.5	53.9	47.4	40.9	35.6	30.4	25.5	20.8	16.4	12.5
Clothes Dryer	-	0.0	0.0	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1	2.2	2.4	2.5	2.6	2.7
Misc	-	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.3
Total	-	11.9	46.4	117.9	235.4	386.5	534.8	641.6	705.4	710.7	732.0	757.7	776.4	771.9	734.4	723.9	707.3	688.3	667.6	644.4	621.9

DSM100 Plus Aggressive Standards

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	25,620	100,057	1,211,158	1,861,674	1,842,652	1,824,041	1,797,607	1,758,869	1,708,589	1,649,485	1,583,882	1,513,276	1,438,608	1,360,569	1,280,876	1,199,109	1,116,047	1,032,562	949,603	868,165
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	6,442	25,769	169,810	321,815	465,779	575,011	632,669	627,390	609,540	588,980	567,010	544,213	520,895	497,303	489,017	479,928	470,346	460,490	450,570	440,811
Room A/C	-	507	1,953	35,202	34,210	33,438	32,655	31,573	30,118	28,408	26,573	24,687	22,793	20,920	19,098	18,340	17,604	16,909	16,273	15,707	15,223
Lighting	-	12,713	53,132	150,241	353,787	728,542	1,305,194	1,989,101	2,569,115	2,910,521	3,050,429	3,084,292	3,074,862	3,048,792	3,015,121	2,976,455	2,933,325	2,885,621	2,833,030	2,775,177	2,711,670
Refrigerator	-	3,004	7,716	(556)	42	12,515	37,303	71,438	110,581	151,247	191,386	230,001	266,678	301,284	333,817	378,015	419,092	457,166	466,795	471,466	474,545
Freezer	-	317	722	1,943	7,301	18,338	35,395	57,135	81,492	106,751	131,289	154,597	176,391	196,533	214,951	231,611	246,493	259,592	261,799	262,615	262,067
Dishwasher	-	54	141	4,385	11,747	22,025	32,483	39,449	42,190	42,617	42,333	41,920	41,506	41,304	41,094	40,884	40,676	40,468	40,262	40,056	39,852
Water Heat	-	27,570	105,986	1,283,738	1,398,471	1,301,735	1,200,975	1,102,942	1,010,407	921,838	834,862	748,099	661,206	574,490	488,632	417,425	347,864	280,668	216,609	156,459	100,943
Clothes Dryer	-	190	459	752	2,638	6,733	13,203	21,566	31,046	40,990	50,992	60,839	70,427	79,661	88,303	96,330	103,727	110,482	116,586	122,031	126,812
Misc	-	622	1,542	2,889	5,096	8,429	12,886	18,130	23,705	29,258	34,593	39,621	44,315	48,991	53,194	56,939	60,244	63,126	62,493	61,726	60,827
Total	-	77,037	297,476	2,859,561	3,996,781	4,440,188	5,069,146	5,761,611	6,284,911	6,549,759	6,600,923	6,534,949	6,415,667	6,271,479	6,112,082	5,985,891	5,848,062	5,700,426	5,506,898	5,305,412	5,100,915
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	8.2	32.5	255.3	498.6	726.0	913.3	1,021.5	1,008.1	967.0	925.6	878.1	829.6	780.7	731.9	717.1	701.4	685.3	669.1	653.3	637.9
Room A/C	-	1.2	4.7	76.2	74.1	71.6	69.5	66.7	63.1	59.0	55.0	50.6	46.2	41.9	37.6	35.4	33.2	31.2	29.3	27.5	26.0
Lighting	-	0.1	0.4	1.2	2.9	5.9	10.6	16.0	20.6	23.2	24.2	24.4	24.2	23.8	23.4	23.0	22.5	22.0	21.5	20.9	20.3
Refrigerator	-	0.3	0.8	(0.2)	(0.2)	0.4	2.5	5.6	9.1	12.7	16.7	20.3	23.6	26.7	29.6	33.7	37.4	40.9	41.4	41.5	41.4
Freezer	-	0.0	0.1	0.2	0.7	1.5	3.0	4.9	7.0	9.2	11.5	13.5	15.4	17.2	18.8	20.2	21.5	22.6	22.7	22.6	22.4
Dishwasher	-	0.0	0.0	0.4	1.2	2.2	3.2	3.8	4.1	4.1	4.1	4.0	3.9	3.9	3.9	3.8	3.8	3.7	3.7	3.7	3.6
Water Heat	-	2.0	7.8	94.8	104.5	97.9	91.9	85.6	79.3	72.8	66.6	60.0	53.5	46.9	40.5	35.2	30.0	25.0	20.3	15.9	12.0
Clothes Dryer	-	0.0	0.0	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1	2.2	2.4	2.5	2.6	2.7
Misc	-	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.3
Total	-	11.9	46.4	427.9	682.0	905.9	1,094.5	1,205.0	1,192.6	1,149.6	1,105.5	1,053.1	998.9	943.9	888.7	871.7	853.4	834.5	811.9	789.4	767.8

Figure 24. Commercial Sector Achievable Potential Scenarios (Electricity Sales)

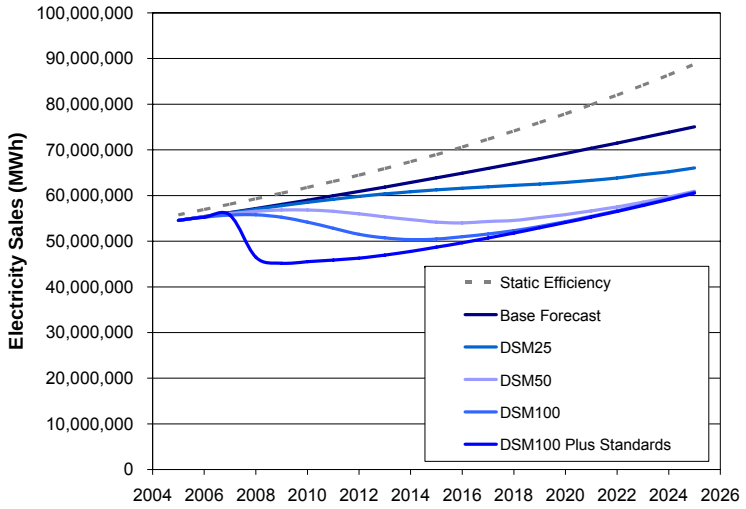

Figure 25. Commercial Sector Achievable Potential Scenarios (Peak Demand)

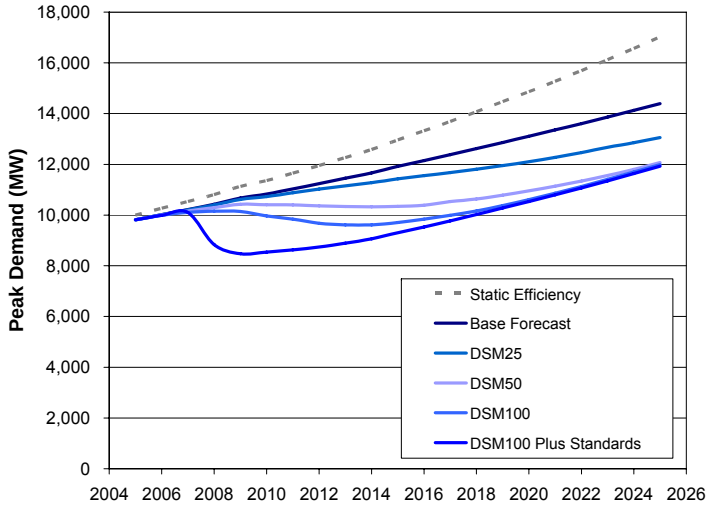

Figure 26. 2015 Commercial Sector Achievable Potential by End Use (DSM50, Electricity Sales)

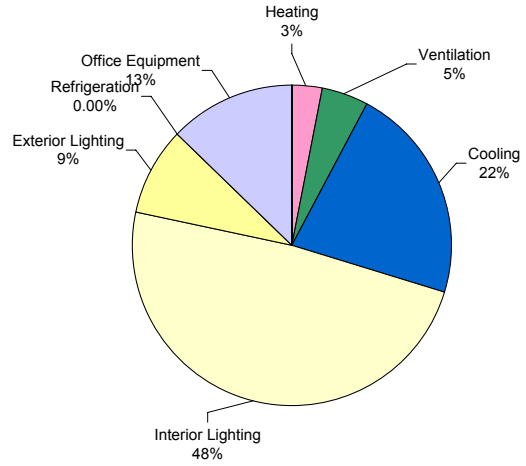

Figure 27. 2015 Commercial Sector Achievable Potential by End Use (DSM50, Peak Demand)

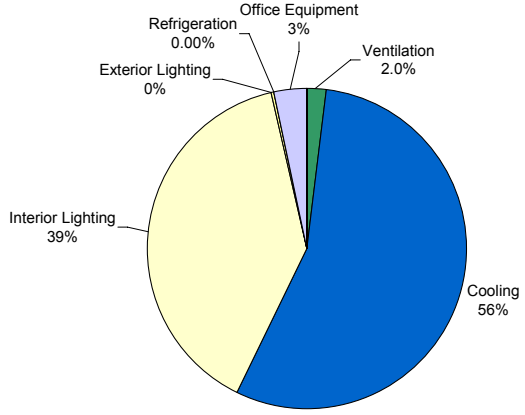

Figure 28. 2015 Commercial Sector Achievable Potential by Sub-sector (DSM50, Electricity Sales)

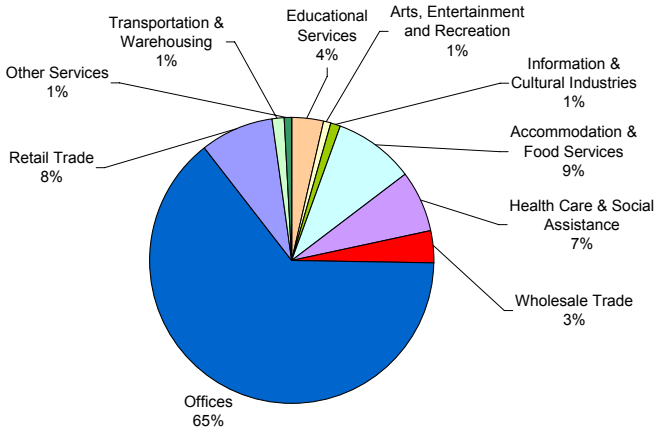

Figure 29. 2015 Commercial Sector Achievable Potential by Sub-sector (DSM50, Peak Demand)

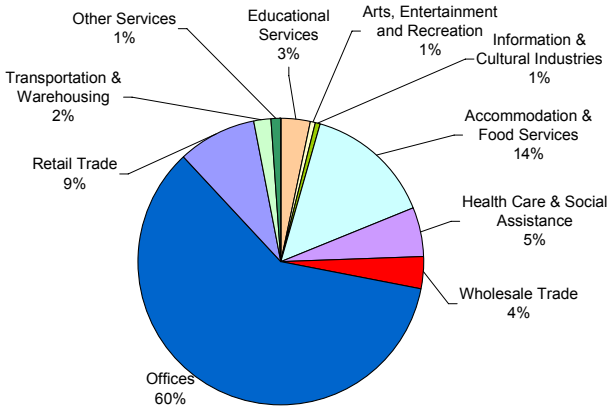

Table 12. Commercial Sector Results by End Use

DSM25 Scenario

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	474	1,618	3,678	6,961	11,831	18,707	28,035	40,248	55,696	74,540	96,630	121,379	147,692	173,985	198,363	218,935	234,195	243,323	246,289	243,711
Ventilation	-	3,789	12,345	26,559	47,053	73,923	106,481	143,031	180,846	216,412	246,003	266,474	275,987	274,388	263,072	244,425	221,135	195,649	169,896	153,240	142,021
Cooling	-	7,266	24,287	53,783	98,475	160,708	241,957	342,245	459,599	589,705	725,949	859,951	982,563	1,085,124	1,160,655	1,222,960	1,255,274	1,257,706	1,232,731	1,381,786	1,524,098
Interior Lighting	-	7,466	25,842	56,519	104,728	176,635	278,788	418,448	603,087	839,499	1,132,492	1,483,207	1,887,334	2,333,722	2,804,060	3,274,003	3,716,887	4,107,344	4,425,504	4,659,514	4,805,933
Exterior Lighting	-	886	3,050	7,006	13,417	23,116	37,132	56,692	83,211	118,234	163,332	219,922	289,007	370,838	464,546	568,672	678,938	789,926	895,313	988,869	1,065,613
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	1,722	5,885	13,404	25,424	43,328	68,728	103,413	149,228	207,878	280,631	367,948	469,084	581,745	701,913	823,967	941,150	1,046,396	1,133,402	1,197,696	1,237,371
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	21,605	73,026	160,950	296,057	489,542	751,792	1,091,864	1,516,220	2,027,425	2,622,947	3,294,132	4,025,355	4,793,509	5,568,231	6,332,389	7,032,318	7,631,216	8,100,169	8,627,393	9,018,747
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	0.3	0.9	1.8	3.3	5.1	7.4	9.9	12.4	14.8	16.8	18.1	18.7	18.5	17.6	16.2	14.6	12.8	11.1	10.1	9.2
Cooling	-	3.2	10.8	23.9	43.8	71.1	106.6	150.0	200.1	254.7	311.6	366.0	414.7	454.5	483.4	507.5	521.1	524.4	518.6	565.3	599.8
Interior Lighting	-	1.0	3.3	7.2	13.5	22.7	36.0	54.2	78.4	109.6	148.6	195.7	250.3	311.2	375.9	441.4	503.9	560.0	606.8	642.6	666.5
Exterior Lighting	-	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.9	1.2	1.6	2.0	2.6	3.2	3.9	4.6	5.3	5.9	6.5
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	0.1	0.3	0.6	1.1	1.9	3.0	4.5	6.5	9.1	12.3	16.1	20.5	25.4	30.5	35.7	40.6	44.8	48.2	50.4	51.5
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	4.5	15.2	33.6	61.8	101.0	153.1	218.8	297.9	388.7	490.1	597.1	705.8	811.6	910.0	1,004.1	1,084.1	1,146.7	1,190.0	1,274.3	1,333.5

DSM50 Scenario

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	1,613	6,034	15,061	31,140	57,053	94,822	143,683	198,195	249,038	287,660	311,041	321,734	330,721	331,580	327,064	321,462	314,492	305,905	295,612	283,700
Ventilation	-	12,704	44,230	99,725	179,254	273,242	362,682	427,951	460,052	462,941	456,106	438,135	402,707	366,537	330,205	294,333	259,545	226,441	195,552	167,310	142,021
Cooling	-	24,373	87,568	206,055	393,045	649,825	957,995	1,279,895	1,570,011	1,791,254	2,139,418	2,436,963	2,590,148	2,841,103	3,074,511	3,324,380	3,537,544	3,696,648	3,797,156	3,846,162	3,858,334
Interior Lighting	-	25,353	96,182	230,194	465,869	848,603	1,413,753	2,162,542	3,035,909	3,918,631	4,687,845	5,269,809	5,656,908	6,092,439	6,231,164	6,252,200	6,233,742	6,184,188	6,114,327	6,022,843	5,908,731
Exterior Lighting	-	3,015	11,415	28,942	61,170	115,687	201,332	325,528	489,097	680,253	873,389	1,038,677	1,158,084	1,240,786	1,287,999	1,341,519	1,350,795	1,357,544	1,361,430	1,362,107	1,359,224
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	5,857	21,963	54,981	114,196	210,768	354,650	548,431	780,123	1,020,813	1,233,310	1,389,855	1,485,060	1,585,440	1,686,850	1,849,490	2,011,900	2,186,671	2,350,128	2,481,293	2,570,716
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	72,916	267,393	634,958	1,244,674	2,155,178	3,385,235	4,888,028	6,533,387	8,122,930	9,677,729	10,884,479	11,614,642	12,457,026	12,942,309	13,388,987	13,714,989	13,965,984	14,124,499	14,175,328	14,122,725
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	0.9	3.1	6.9	12.4	18.9	24.9	29.3	31.4	31.4	31.0	29.6	27.1	24.5	21.9	19.4	17.1	14.8	12.7	10.9	9.2
Cooling	-	10.8	38.8	91.0	173.1	282.1	410.3	540.1	654.5	741.2	872.4	963.9	1,000.2	1,060.5	1,115.3	1,158.5	1,193.9	1,218.1	1,230.2	1,231.4	1,223.9
Interior Lighting	-	3.2	12.3	29.5	60.0	109.3	182.7	280.5	395.6	512.8	618.2	699.5	755.7	821.0	844.8	852.1	853.7	850.9	845.1	836.2	824.1
Exterior Lighting	-	0.0	0.1	0.1	0.3	0.6	1.0	1.7	2.6	3.8	5.0	6.0	6.8	7.3	7.7	8.1	8.3	8.4	8.6	8.7	8.8
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	0.3	0.9	2.4	5.0	9.2	15.5	23.9	34.0	44.5	53.8	60.7	64.8	74.0	87.7	113.6	144.0	177.5	209.6	236.4	255.8
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	15.2	55.2	129.9	250.8	420.1	634.4	875.6	1,118.1	1,333.7	1,580.4	1,759.7	1,854.5	1,987.4	2,077.6	2,151.8	2,217.0	2,269.7	2,306.3	2,323.5	2,321.7

Commercial Sector Results by End Use *(continued)*

DSM100 Scenario

Commercial Electric by End Use

Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	3,058	12,655	34,737	76,724	141,161	215,804	277,529	313,877	337,623	344,201	344,175	343,313	341,045	337,149	331,724	324,891	316,695	307,141	296,229	283,984
Ventilation	-	23,667	87,412	199,604	338,399	454,327	515,437	541,772	535,177	504,766	472,301	438,135	402,707	366,537	330,205	294,333	259,545	226,441	195,552	167,310	142,021
Cooling	-	45,452	174,894	427,990	809,900	1,260,020	1,675,187	2,230,976	2,710,748	3,048,146	3,358,844	3,651,777	3,879,041	4,012,708	4,063,541	4,086,840	4,080,140	4,059,230	4,031,954	4,002,275	3,972,490
Interior Lighting	-	47,995	200,863	526,751	1,140,069	2,098,490	3,267,099	4,354,756	5,149,315	5,904,108	6,193,919	6,254,069	6,283,077	6,299,488	6,301,570	6,288,459	6,257,673	6,207,667	6,137,034	6,044,576	5,929,396
Exterior Lighting	-	5,725	24,074	67,918	157,561	315,105	543,310	799,515	1,012,878	1,160,266	1,267,210	1,295,612	1,309,378	1,321,781	1,332,596	1,344,439	1,354,093	1,361,239	1,365,542	1,366,654	1,364,221
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	11,111	46,114	127,315	284,741	537,777	859,697	1,167,960	1,384,627	1,550,395	1,752,051	1,936,912	2,157,864	2,360,049	2,500,425	2,579,010	2,619,517	2,641,720	2,655,297	2,663,901	2,668,747
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	137,008	546,012	1,384,316	2,807,394	4,806,880	7,076,532	9,372,509	11,106,622	12,505,304	13,388,526	13,920,680	14,375,381	14,701,608	14,865,487	14,924,805	14,895,859	14,812,993	14,692,520	14,540,945	14,360,860

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	1.6	6.0	13.8	23.4	31.3	35.3	37.1	36.4	34.1	32.0	29.6	27.1	24.5	21.9	19.4	17.1	14.8	12.7	10.9	9.2
Cooling	-	20.1	77.1	187.0	349.9	531.2	695.0	907.1	1,065.4	1,160.6	1,256.2	1,308.1	1,346.6	1,365.8	1,366.8	1,365.8	1,355.5	1,339.7	1,321.0	1,300.9	1,280.5
Interior Lighting	-	6.1	25.7	67.4	146.8	270.2	422.2	565.2	671.9	776.1	822.8	835.3	843.4	849.8	854.2	856.5	856.4	853.5	847.6	838.6	826.4
Exterior Lighting	-	0.0	0.1	0.3	0.8	1.7	3.0	4.5	5.8	6.6	7.3	7.6	7.8	8.0	8.2	8.4	8.5	8.7	8.8	8.9	9.0
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	0.5	2.0	5.5	12.4	23.4	37.5	50.9	60.4	72.2	97.3	130.3	170.7	208.5	235.2	250.5	258.7	263.8	267.7	271.0	274.1
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	28.4	111.0	274.1	533.3	857.8	1,192.9	1,564.8	1,839.9	2,049.6	2,215.7	2,310.8	2,395.5	2,456.6	2,486.4	2,500.7	2,496.2	2,480.5	2,457.8	2,430.3	2,399.2

DSM100 Plus Standards

Commercial Electric by End Use

Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	3,058	12,655	335,814	339,370	342,942	346,133	348,448	349,704	349,985	349,383	347,901	345,488	342,066	337,554	331,869	324,942	316,714	307,147	296,231	283,985
Ventilation	-	23,667	87,412	650,161	632,324	611,909	588,884	563,275	535,177	504,766	472,301	438,135	402,707	366,537	330,205	294,333	259,545	226,441	195,552	167,310	142,021
Cooling	-	45,452	174,894	2,216,490	3,186,382	3,472,077	3,793,186	4,057,401	4,219,567	4,295,081	4,316,881	4,309,310	4,285,795	4,253,118	4,214,854	4,197,922	4,176,226	4,151,565	4,125,298	4,098,642	4,072,761
Interior Lighting	-	47,995	200,863	4,800,355	5,838,603	5,922,199	6,001,634	6,075,849	6,143,670	6,203,892	6,255,281	6,296,551	6,326,340	6,343,208	6,345,650	6,332,924	6,302,673	6,253,395	6,183,702	6,089,841	5,973,704
Exterior Lighting	-	5,725	24,074	1,082,934	1,178,705	1,197,412	1,215,844	1,233,897	1,251,453	1,268,377	1,284,521	1,299,714	1,313,770	1,326,483	1,337,624	1,349,813	1,359,832	1,367,363	1,372,069	1,373,600	1,371,603
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	11,111	46,114	1,577,427	1,728,954	1,930,764	2,139,846	2,301,643	2,401,416	2,459,571	2,497,951	2,527,989	2,554,032	2,577,427	2,598,467	2,617,106	2,633,198	2,646,576	2,657,086	2,664,603	2,669,043
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	137,008	546,012	10,663,180	12,904,338	13,477,303	14,085,527	14,580,513	14,900,987	15,081,671	15,176,317	15,219,600	15,228,132	15,208,840	15,164,355	15,123,966	15,056,416	14,962,054	14,840,855	14,690,228	14,513,117

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	1.6	6.0	44.6	43.7	41.9	40.3	38.4	36.4	34.1	32.0	29.6	27.1	24.5	21.9	19.4	17.1	14.8	12.7	10.9	9.2
Cooling	-	20.1	77.1	855.6	1,290.2	1,338.6	1,403.5	1,458.7	1,493.2	1,505.6	1,510.1	1,500.0	1,483.6	1,463.2	1,440.0	1,426.3	1,410.4	1,393.0	1,374.8	1,356.3	1,338.0
Interior Lighting	-	6.1	25.7	607.7	754.9	764.8	779.0	792.3	805.2	816.2	830.6	840.4	848.8	855.3	859.9	862.3	862.3	859.6	854.0	845.0	832.7
Exterior Lighting	-	0.0	0.1	6.2	6.5	6.6	6.9	7.1	7.3	7.5	7.8	8.0	8.2	8.4	8.5	8.7	8.9	9.0	9.1	9.2	9.2
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	0.5	2.0	78.7	105.0	139.9	176.7	204.9	221.8	231.0	237.5	242.3	246.4	250.4	254.1	257.8	261.3	264.7	268.0	271.2	274.2
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	28.4	111.0	1,592.8	2,200.2	2,291.8	2,406.3	2,501.4	2,563.9	2,594.5	2,618.0	2,620.3	2,614.1	2,601.7	2,584.5	2,574.5	2,559.9	2,541.1	2,518.6	2,492.4	2,463.3

Table 13. Commercial Sector Results by Sub-sector

DSM25 Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	758	2,576	5,641	10,364	17,184	26,518	38,761	54,245	73,185	95,632	121,411	150,061	180,784	212,417	244,015	273,548	299,378	320,162	337,009	347,862
Arts, Entertainment and Recreation	-	236	789	1,745	3,190	5,201	7,827	11,081	14,931	19,308	24,124	29,308	34,831	40,721	47,043	53,695	60,852	68,449	76,339	85,585	95,022
Information & Cultural Industries	-	261	888	1,950	3,571	5,874	8,963	12,917	17,774	23,520	30,086	37,341	45,094	53,095	61,029	68,590	75,377	81,068	85,435	89,315	91,991
Accommodation & Food Services	-	2,213	7,430	16,512	30,429	50,149	76,513	110,109	151,122	199,202	253,393	312,127	373,307	434,440	492,817	548,425	596,409	634,576	661,455	711,891	753,048
Health Care & Social Assistance	-	1,542	5,195	11,620	21,569	35,836	55,195	80,311	111,634	149,284	192,930	241,698	294,094	347,997	400,756	450,668	493,925	528,201	552,088	578,398	595,533
Wholesale Trade	-	940	3,115	6,841	12,455	20,276	30,561	43,455	58,945	76,824	96,667	117,842	139,530	160,766	180,501	198,215	212,564	222,852	228,724	233,805	235,187
Offices	-	12,588	42,836	94,355	174,023	289,257	447,186	654,546	916,941	1,238,018	1,618,576	2,055,638	2,541,525	3,063,050	3,601,218	4,144,683	4,655,906	5,107,303	5,475,616	5,885,564	6,200,315
Retail Trade	-	2,431	8,074	17,690	32,157	52,300	78,752	111,837	151,436	196,884	246,925	299,740	353,044	404,228	450,554	490,367	520,764	540,287	548,446	552,287	547,270
Transportation & Warehousing	-	419	1,398	3,026	5,458	8,847	13,312	18,928	25,708	33,580	42,370	51,793	61,440	70,795	79,267	86,391	91,571	94,490	95,076	94,146	91,457
Other Services	-	216	725	1,571	2,840	4,618	6,965	9,919	13,483	17,619	22,244	27,234	32,428	37,633	42,628	47,339	51,402	54,613	56,827	59,392	61,062
Total	-	21,605	73,026	160,950	296,057	489,542	751,792	1,091,864	1,516,220	2,027,425	2,622,947	3,294,132	4,025,355	4,793,509	5,568,231	6,332,389	7,032,318	7,631,216	8,100,169	8,627,393	9,018,747
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.1	0.4	0.9	1.7	2.7	4.2	6.1	8.5	11.4	14.7	18.4	22.4	26.5	30.7	34.8	38.5	41.7	44.3	46.8	48.5
Arts, Entertainment and Recreation	-	0.0	0.1	0.2	0.4	0.7	1.0	1.4	1.9	2.5	3.2	3.8	4.5	5.2	5.9	6.6	7.3	8.0	8.6	9.8	10.9
Information & Cultural Industries	-	0.0	0.1	0.2	0.3	0.6	0.9	1.3	1.8	2.4	3.0	3.8	4.6	5.4	6.2	7.0	7.7	8.3	8.7	9.2	9.6
Accommodation & Food Services	-	0.8	2.8	6.1	11.2	18.2	27.3	38.5	51.4	65.6	80.4	94.8	107.7	118.5	126.6	133.2	136.9	138.0	136.5	147.2	154.9
Health Care & Social Assistance	-	0.2	0.8	1.8	3.4	5.5	8.4	12.1	16.5	21.6	27.3	33.3	39.4	45.2	50.6	55.5	59.4	62.2	63.7	67.3	69.5
Wholesale Trade	-	0.2	0.7	1.5	2.7	4.4	6.6	9.3	12.4	15.8	19.5	23.1	26.4	29.3	31.7	33.5	34.7	35.1	34.9	35.3	35.2
Offices	-	2.4	8.0	17.7	32.7	53.8	82.2	118.6	163.1	215.5	275.6	341.3	410.8	481.7	551.3	621.0	684.0	737.6	779.1	845.1	893.6
Retail Trade	-	0.5	1.8	3.9	7.1	11.6	17.3	24.3	32.4	41.3	50.7	59.8	68.1	75.1	80.3	83.9	85.6	85.4	83.6	82.6	80.4
Transportation & Warehousing	-	0.1	0.4	0.8	1.4	2.3	3.4	4.8	6.5	8.4	10.5	12.6	14.6	16.5	18.1	19.3	20.1	20.4	20.2	20.1	19.7
Other Services	-	0.1	0.2	0.4	0.7	1.2	1.8	2.5	3.3	4.3	5.3	6.3	7.2	8.1	8.8	9.4	9.9	10.2	10.3	10.8	11.2
Total	-	4.5	15.2	33.6	61.8	101.0	153.1	218.8	297.9	388.7	490.1	597.1	705.8	811.6	910.0	1,004.1	1,084.1	1,146.7	1,190.0	1,274.3	1,333.5

DSM50 Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	2,562	9,467	22,395	44,042	76,940	122,325	179,068	242,668	305,552	362,005	404,489	430,605	459,920	471,773	478,275	481,138	482,059	480,748	476,725	469,987
Arts, Entertainment and Recreation	-	795	2,854	6,699	12,729	20,971	31,011	42,261	54,310	66,837	80,444	93,144	103,151	114,186	123,713	135,381	145,119	154,550	163,925	173,165	182,222
Information & Cultural Industries	-	881	3,241	7,626	14,742	25,049	38,429	54,062	70,428	85,598	98,811	108,411	113,810	119,672	121,014	121,846	121,047	119,767	118,069	115,984	113,549
Accommodation & Food Services	-	7,455	27,071	64,581	125,981	215,241	331,589	467,704	609,871	740,736	883,703	997,228	1,062,313	1,132,400	1,187,270	1,250,692	1,302,469	1,343,774	1,373,484	1,389,888	1,393,622
Health Care & Social Assistance	-	5,209	19,042	45,975	91,038	158,393	249,099	358,638	475,564	583,690	682,915	754,698	793,756	837,844	857,365	880,847	895,299	904,722	908,090	904,681	894,909
Wholesale Trade	-	3,174	11,397	26,932	52,053	88,137	134,594	188,150	242,925	291,704	333,331	360,865	372,583	381,115	380,661	379,793	376,785	371,281	363,722	353,904	342,090
Offices	-	42,490	157,011	373,065	735,294	1,285,638	2,045,301	2,997,090	4,068,582	5,135,357	6,208,382	7,068,152	7,616,751	8,272,840	8,673,181	9,028,016	9,298,711	9,520,126	9,676,479	9,756,286	9,761,940
Retail Trade	-	8,209	29,540	69,591	134,092	226,141	343,196	475,461	606,837	719,165	807,717	860,782	878,945	891,956	883,108	874,612	861,351	844,366	823,370	797,658	767,567
Transportation & Warehousing	-	1,414	5,128	11,958	22,981	38,947	59,698	83,718	108,000	128,789	144,245	152,685	154,587	154,771	150,331	144,881	138,652	131,842	124,625	117,087	109,331
Other Services	-	727	2,642	6,134	11,721	19,720	29,994	41,877	54,201	65,501	76,175	84,026	88,142	92,324	93,894	94,644	94,417	93,499	91,987	89,949	87,508
Total	-	72,916	267,393	634,958	1,244,674	2,155,178	3,385,235	4,888,028	6,533,387	8,122,930	9,677,729	10,884,479	11,614,642	12,457,026	12,942,309	13,388,987	13,714,989	13,965,984	14,124,499	14,175,328	14,122,725
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.4	1.5	3.5	6.9	11.9	18.6	26.6	35.3	43.6	51.7	57.9	61.8	67.0	70.0	71.0	71.8	72.3	72.5	72.3	71.6
Arts, Entertainment and Recreation	-	0.1	0.3	0.8	1.6	2.6	3.9	5.3	6.8	8.1	10.0	11.6	12.8	14.3	15.8	17.4	18.9	20.2	21.6	22.8	24.0
Information & Cultural Industries	-	0.1	0.3	0.7	1.4	2.5	3.8	5.3	7.0	8.5	9.9	11.0	11.6	12.4	12.7	12.9	13.0	13.0	12.9	12.8	12.6
Accommodation & Food Services	-	2.8	10.0	23.4	44.5	72.8	106.2	140.3	170.6	193.8	226.7	249.2	258.0	269.9	281.0	294.1	305.5	314.4	320.4	323.0	322.6
Health Care & Social Assistance	-	0.8	3.0	7.0	13.7	23.1	35.1	48.6	62.0	73.5	86.1	94.7	98.8	104.7	108.4	111.8	114.6	116.8	118.2	118.6	118.0
Wholesale Trade	-	0.7	2.5	5.8	11.1	18.4	27.1	36.4	44.8	51.4	57.7	61.4	62.5	63.8	64.0	63.9	63.6	62.9	61.8	60.3	58.4
Offices	-	8.0	29.2	68.7	133.5	226.2	347.4	489.7	640.6	782.9	948.2	1,074.4	1,147.6	1,251.7	1,324.1	1,381.7	1,433.6	1,478.1	1,512.1	1,533.3	1,541.4
Retail Trade	-	1.8	6.5	15.3	29.2	48.1	70.7	93.9	114.2	129.1	141.4	147.4	148.3	149.0	147.1	145.0	142.6	139.6	135.9	131.4	126.2
Transportation & Warehousing	-	0.4	1.3	3.0	5.8	9.7	14.6	20.0	25.1	29.2	32.9	34.9	35.2	35.6	35.1	34.4	33.5	32.3	31.0	29.5	27.9
Other Services	-	0.2	0.7	1.5	2.9	4.8	7.0	9.5	11.7	13.6	15.8	17.3	18.0	18.9	19.4	19.8	19.9	20.0	19.8	19.5	19.1
Total	-	15.2	55.2	129.9	250.8	420.1	634.4	875.6	1,118.1	1,333.7	1,580.4	1,759.7	1,854.5	1,987.4	2,077.6	2,151.8	2,217.0	2,269.7	2,306.3	2,323.5	2,321.7

Commercial Sector Results by Sub-sector *(continued)*

DSM100 Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	4,822	19,427	49,300	101,001	175,564	262,298	344,784	405,287	458,408	484,233	493,199	500,270	504,885	506,132	505,288	502,235	497,514	491,356	483,829	474,944
Arts, Entertainment and Recreation	-	1,486	5,719	13,948	26,314	41,515	58,006	75,610	90,824	104,152	116,285	126,146	135,198	144,094	152,670	161,802	170,597	179,102	187,362	195,415	203,291
Information & Cultural Industries	-	1,654	6,579	16,360	32,172	53,016	75,125	94,822	108,303	118,972	123,317	124,321	124,645	124,512	123,954	123,114	121,918	120,386	118,531	116,362	113,890
Accommodation & Food Services	-	13,975	54,908	138,852	276,972	462,284	663,130	881,936	1,053,020	1,164,873	1,259,359	1,336,613	1,401,940	1,448,766	1,472,473	1,481,058	1,477,876	1,468,558	1,455,921	1,441,212	1,425,027
Health Care & Social Assistance	-	9,795	38,959	100,655	206,230	353,348	515,386	668,923	776,313	854,686	896,120	926,619	950,708	966,387	971,865	970,770	963,981	953,553	940,497	925,269	908,111
Wholesale Trade	-	5,966	23,255	58,515	116,195	192,773	273,929	346,971	395,360	423,231	432,892	436,779	436,386	432,580	424,698	414,386	402,077	388,692	374,704	360,347	345,760
Offices	-	79,855	321,064	816,533	1,673,757	2,913,109	4,366,815	5,889,744	7,078,661	8,107,212	8,784,323	9,187,281	9,546,423	9,819,012	9,981,109	10,070,895	10,100,149	10,091,699	10,056,036	9,996,958	9,915,596
Retail Trade	-	15,431	60,249	150,849	297,195	486,818	679,958	841,494	941,495	998,317	1,013,378	1,013,985	1,009,110	997,263	976,425	949,785	918,480	884,614	849,301	813,115	776,416
Transportation & Warehousing	-	2,661	10,493	26,145	51,906	86,363	122,260	151,542	168,318	177,564	176,358	172,158	166,786	160,748	154,144	147,348	140,215	132,822	125,223	117,466	109,599
Other Services	-	1,363	5,360	13,158	25,651	42,091	59,626	76,682	89,041	97,890	102,262	103,578	103,915	103,362	102,017	100,359	98,330	96,052	93,589	90,973	88,226
Total	-	137,008	546,012	1,384,316	2,807,394	4,806,880	7,076,532	9,372,509	11,106,622	12,505,304	13,388,526	13,920,680	14,375,381	14,701,608	14,865,487	14,924,805	14,895,859	14,812,993	14,692,520	14,540,945	14,360,860
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.8	3.0	7.6	15.3	25.8	37.4	49.2	58.2	67.2	73.1	74.6	76.0	76.9	77.3	77.6	77.3	76.8	76.0	75.0	73.8
Arts, Entertainment and Recreation	-	0.2	0.7	1.7	3.3	5.1	7.0	9.4	11.5	13.3	15.2	16.7	18.0	19.3	20.5	21.7	22.8	23.8	24.8	25.8	26.8
Information & Cultural Industries	-	0.2	0.6	1.6	3.1	5.2	7.3	9.4	10.9	12.1	12.8	13.0	13.2	13.3	13.3	13.3	13.3	13.2	13.1	12.9	12.8
Accommodation & Food Services	-	5.2	19.8	48.2	90.6	138.5	182.2	236.0	275.3	294.4	315.7	332.7	347.0	356.2	359.5	359.9	357.0	352.5	347.2	341.5	335.7
Health Care & Social Assistance	-	1.5	6.0	14.9	29.4	47.5	66.1	85.5	99.1	108.9	116.2	120.8	124.9	127.7	128.9	129.3	128.7	127.5	125.9	124.1	122.0
Wholesale Trade	-	1.3	5.0	12.4	23.7	37.1	49.7	61.4	69.1	73.2	75.7	76.5	76.6	76.1	74.6	72.8	70.5	67.9	65.3	62.6	59.9
Offices	-	14.9	58.7	145.5	287.1	472.6	676.2	911.5	1,091.2	1,245.8	1,367.1	1,436.6	1,501.4	1,552.1	1,583.2	1,604.0	1,612.6	1,613.7	1,609.8	1,602.1	1,591.2
Retail Trade	-	3.4	13.2	32.5	62.1	96.1	126.4	151.1	166.5	173.0	176.4	176.3	175.4	173.0	168.7	163.4	157.1	150.2	143.2	136.1	129.2
Transportation & Warehousing	-	0.7	2.6	6.5	12.7	20.4	28.0	34.9	39.1	41.2	41.7	41.3	40.5	39.4	38.0	36.6	35.1	33.4	31.7	30.0	28.3
Other Services	-	0.3	1.3	3.2	6.0	9.4	12.7	16.3	19.0	20.7	21.9	22.4	22.7	22.7	22.4	22.2	21.8	21.3	20.8	20.2	19.7
Total	-	28.4	111.0	274.1	533.3	857.8	1,192.9	1,564.8	1,839.9	2,049.6	2,215.7	2,310.8	2,395.5	2,456.6	2,486.4	2,500.7	2,496.2	2,480.5	2,457.8	2,430.3	2,399.2

DSM100 Plus Standards

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	4,822	19,427	390,423	471,295	482,474	493,773	502,998	509,278	513,128	515,295	516,225	516,097	514,959	512,798	510,421	506,890	502,163	496,190	488,932	480,354
Arts, Entertainment and Recreation	-	1,486	5,719	83,333	94,748	104,663	114,922	125,100	134,866	144,107	152,837	161,105	168,961	176,457	183,643	191,442	199,022	206,433	213,717	218,347	223,144
Information & Cultural Industries	-	1,654	6,579	104,228	116,664	118,729	120,695	122,389	123,709	124,651	125,249	125,529	125,500	125,162	124,515	123,651	122,467	120,964	119,146	117,020	114,593
Accommodation & Food Services	-	13,975	54,908	1,023,800	1,223,261	1,304,170	1,391,269	1,460,618	1,502,447	1,522,529	1,529,723	1,529,828	1,525,729	1,518,747	1,509,509	1,502,058	1,492,470	1,481,008	1,467,886	1,453,308	1,437,487
Health Care & Social Assistance	-	9,795	38,959	789,346	871,325	905,482	941,551	970,570	988,729	998,005	1,001,592	1,001,579	998,970	994,185	987,386	980,410	971,322	960,183	947,043	931,973	915,069
Wholesale Trade	-	5,966	23,255	453,816	481,374	487,034	492,919	495,208	492,506	485,895	476,861	466,351	454,836	442,547	429,615	416,900	403,639	389,924	375,841	361,474	346,906
Offices	-	79,855	321,064	6,471,613	8,204,168	8,624,345	9,071,257	9,444,896	9,703,505	9,870,032	9,980,430	10,057,834	10,113,155	10,150,695	10,171,790	10,194,873	10,199,123	10,184,175	10,149,371	10,094,036	10,017,625
Retail Trade	-	15,431	60,249	1,065,312	1,131,290	1,141,205	1,150,964	1,152,750	1,143,859	1,126,631	1,104,120	1,078,217	1,049,850	1,019,485	987,407	955,399	921,987	887,415	851,919	815,735	779,104
Transportation & Warehousing	-	2,661	10,493	193,034	204,662	201,758	198,707	195,110	190,781	185,789	180,276	174,346	168,062	161,461	154,570	147,646	140,466	133,061	125,466	117,719	109,864
Other Services	-	1,363	5,360	88,276	105,550	107,445	109,470	110,875	111,308	110,904	109,933	108,587	106,973	105,141	103,122	101,166	99,029	96,727	94,275	91,685	88,970
Total	-	137,008	546,012	10,663,180	12,904,338	13,477,303	14,085,527	14,580,513	14,900,987	15,081,671	15,176,317	15,219,600	15,228,132	15,208,840	15,164,355	15,123,966	15,056,416	14,962,054	14,840,855	14,690,228	14,513,117
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.8	3.0	50.9	72.4	74.0	76.1	77.9	79.2	80.0	80.7	80.9	80.9	80.7	80.3	80.0	79.6	79.1	78.3	77.4	76.2
Arts, Entertainment and Recreation	-	0.2	0.7	8.7	12.6	13.9	15.4	16.9	18.3	19.5	20.7	21.7	22.7	23.6	24.4	25.4	26.4	27.3	28.2	28.9	29.5
Information & Cultural Industries	-	0.2	0.6	9.4	11.7	12.0	12.3	12.6	12.9	13.1	13.3	13.4	13.5	13.5	13.5	13.5	13.5	13.4	13.3	13.1	13.0
Accommodation & Food Services	-	5.2	19.8	234.2	323.9	340.9	361.8	378.5	388.2	391.5	392.7	390.3	386.2	381.2	375.5	371.4	366.7	361.6	356.2	350.8	345.4
Health Care & Social Assistance	-	1.5	6.0	89.8	115.5	120.0	125.8	130.6	133.7	135.2	136.4	136.3	135.8	135.0	133.8	133.0	131.8	130.5	128.9	127.1	125.1
Wholesale Trade	-	1.3	5.0	72.1	86.4	87.2	88.8	89.7	89.4	88.2	86.7	84.6	82.1	79.4	76.6	74.1	71.5	68.8	66.1	63.4	60.7
Offices	-	14.9	58.7	893.7	1,303.8	1,368.6	1,447.8	1,515.8	1,564.3	1,593.9	1,619.3	1,632.2	1,640.2	1,644.5	1,645.9	1,651.3	1,653.6	1,652.9	1,649.3	1,642.9	1,633.7
Retail Trade	-	3.4	13.2	177.2	203.1	204.1	206.6	207.4	205.9	202.3	198.4	192.8	186.5	179.8	172.7	166.0	159.0	151.9	144.8	137.7	130.8
Transportation & Warehousing	-	0.7	2.6	40.1	47.8	47.5	47.5	47.3	46.7	45.7	44.7	43.4	41.9	40.3	38.6	37.1	35.5	33.8	32.1	30.4	28.6
Other Services	-	0.3	1.3	16.6	23.1	23.6	24.3	24.8	25.1	25.1	25.0	24.6	24.2	23.7	23.2	22.8	22.3	21.8	21.3	20.8	20.2
Total	-	28.4	111.0	1,592.8	2,200.2	2,291.8	2,406.3	2,501.4	2,563.9	2,594.5	2,618.0	2,620.3	2,614.1	2,601.7	2,584.5	2,574.5	2,559.9	2,541.1	2,518.6	2,492.4	2,463.3

Figure 30. Industrial Sector Achievable Potential Scenarios (Electricity Sales)

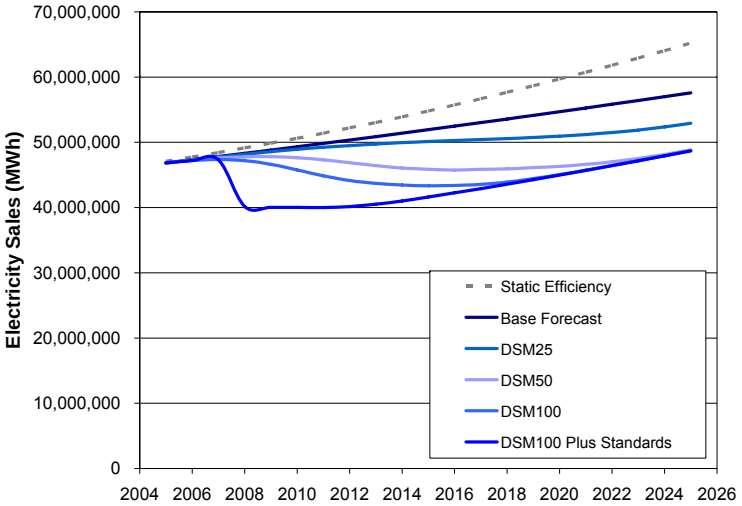

Figure 31. Industrial Sector Achievable Potential Scenarios (Peak Demand)

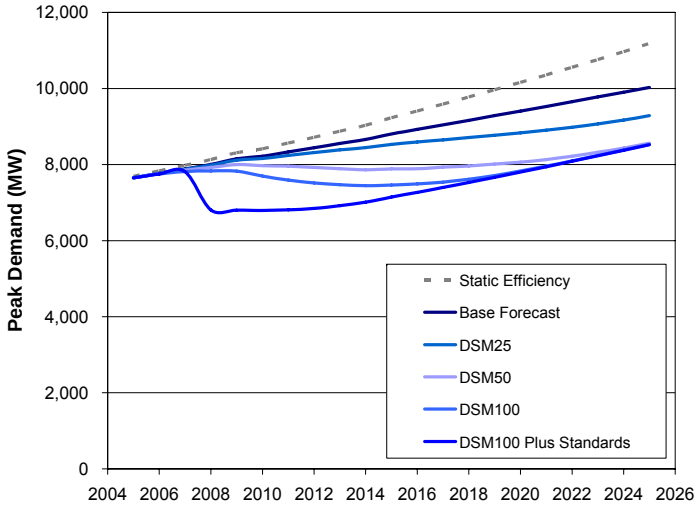

Figure 32. 2015 Industrial Sector Achievable Potential by End Use (DSM50, Electricity Sales)

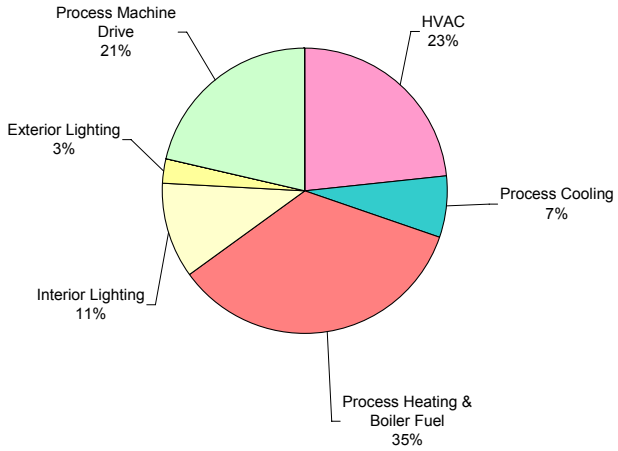

Figure 33. 2015 Industrial Sector Achievable Potential by End Use (DSM50, Peak Demand)

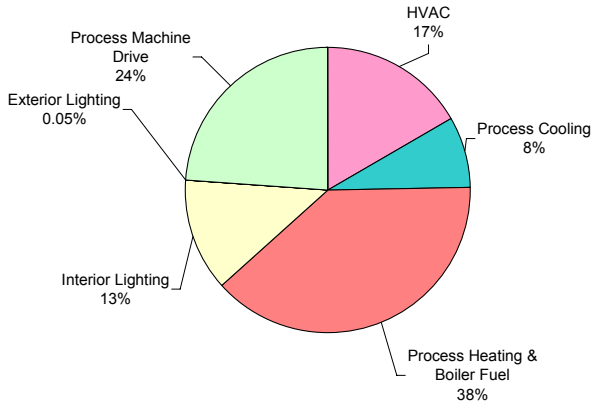

Figure 34. 2015 Industrial Sector Achievable Potential by Sub-sector (DSM50, Electricity Sales)

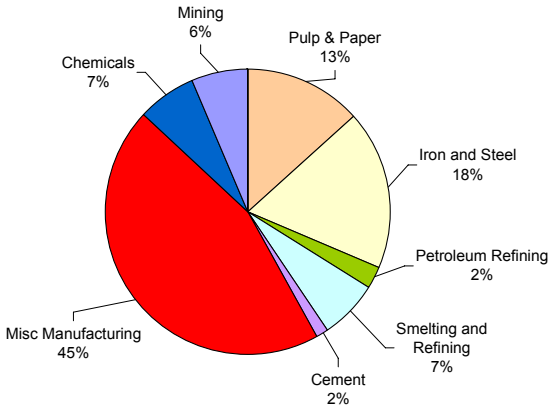

Figure 35. 2015 Industrial Sector Achievable Potential by Sub-sector (DSM50, Peak Demand)

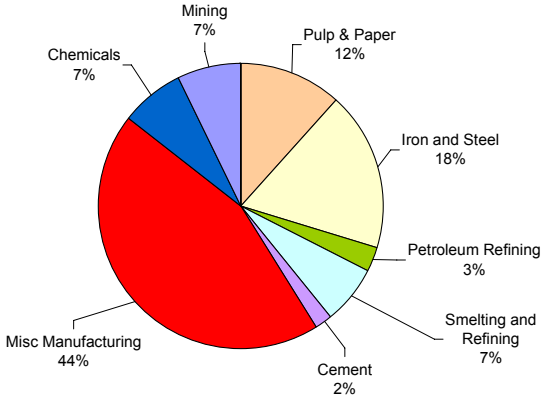

Table 14. Industrial Sector Results by End Use

DSM25 Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	4,521	14,826	32,219	57,949	93,120	138,616	195,053	262,749	341,602	430,820	528,465	630,949	732,780	826,866	912,667	979,371	1,021,965	1,050,351	1,050,759	1,030,753
Process Cooling	-	791	2,683	6,060	11,386	19,198	30,085	44,638	63,368	86,584	114,228	145,702	179,732	214,335	246,987	274,998	296,040	308,651	312,502	308,317	297,502
Process Heating & Boiler Fuel	-	2,346	8,019	18,296	34,802	59,573	95,093	144,301	210,529	297,321	408,099	545,601	711,087	903,373	1,117,855	1,345,887	1,574,960	1,790,042	1,976,078	2,121,032	2,218,324
Interior Lighting	-	1,006	3,504	7,690	14,236	23,953	37,693	56,385	80,965	112,250	150,779	196,627	249,214	307,131	368,065	428,918	486,084	536,108	576,206	604,701	621,713
Exterior Lighting	-	182	626	1,431	2,722	4,649	7,394	11,176	16,255	22,925	31,485	42,186	55,144	70,270	87,238	105,607	124,612	143,341	160,838	176,212	188,114
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	9,924	32,398	69,924	124,420	196,587	285,154	386,188	492,743	595,220	682,678	745,005	775,325	771,709	737,394	679,445	606,552	526,987	447,372	372,322	304,652
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	18,771	62,057	135,619	245,515	397,079	594,033	837,742	1,126,610	1,455,902	1,818,089	2,203,586	2,601,450	2,999,597	3,384,405	3,747,522	4,067,619	4,327,093	4,523,347	4,633,343	4,661,058
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	0.5	1.5	3.3	5.9	9.5	14.0	19.6	26.2	34.1	43.2	53.3	64.4	75.9	87.1	98.0	107.5	115.1	122.0	126.0	127.5
Process Cooling	-	0.1	0.5	1.1	2.0	3.4	5.4	8.0	11.3	15.5	20.6	26.4	32.7	39.1	45.3	50.6	54.7	57.3	58.3	57.8	56.0
Process Heating & Boiler Fuel	-	0.4	1.3	3.0	5.7	9.8	15.6	23.7	34.7	49.2	67.8	90.9	118.9	151.6	188.3	227.5	267.2	304.7	337.6	363.7	381.7
Interior Lighting	-	0.2	0.6	1.3	2.5	4.2	6.6	9.9	14.3	19.9	26.9	35.4	45.1	56.0	67.6	79.4	90.6	100.7	109.1	115.3	119.4
Exterior Lighting	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	1.6	5.2	11.3	20.3	32.2	46.9	63.7	81.5	98.9	114.2	125.4	131.4	131.8	126.9	117.9	106.1	93.1	79.8	67.2	55.6
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	2.8	9.1	20.0	36.5	59.0	88.4	124.9	168.2	217.6	272.7	331.5	392.7	454.5	515.4	573.6	626.5	671.3	707.2	730.4	740.7

DSM50 Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	15,169	53,406	123,351	232,723	386,683	585,473	818,725	1,059,111	1,267,128	1,423,168	1,504,819	1,532,645	1,648,292	1,735,550	1,851,387	1,984,062	2,111,317	2,209,537	2,266,229	2,283,772
Process Cooling	-	2,689	9,988	24,707	50,508	91,200	148,771	220,276	295,792	361,279	406,298	429,435	436,088	449,522	445,992	442,914	439,287	433,432	423,849	410,089	392,780
Process Heating & Boiler Fuel	-	7,992	30,081	75,888	159,750	301,104	522,003	838,497	1,244,509	1,696,345	2,118,579	2,441,825	2,642,254	2,742,037	2,778,850	2,846,310	2,841,473	2,834,698	2,823,352	2,803,276	2,770,601
Interior Lighting	-	3,418	13,049	31,372	63,548	115,794	193,196	296,511	418,368	542,946	651,860	732,767	783,548	819,931	836,098	831,628	827,967	814,089	797,128	777,175	756,041
Exterior Lighting	-	621	2,344	5,918	12,429	23,314	40,193	64,357	95,798	132,123	168,363	198,741	219,629	232,340	237,664	242,145	240,858	239,871	239,208	238,691	236,062
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	33,368	116,982	266,739	487,172	757,402	1,026,252	1,232,139	1,338,804	1,351,330	1,299,062	1,424,463	1,555,260	1,747,788	1,972,522	2,178,656	2,320,778	2,385,789	2,392,113	2,367,916	2,334,459
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	63,256	225,850	527,974	1,006,130	1,675,498	2,515,888	3,470,505	4,452,382	5,351,151	6,067,329	6,732,051	7,169,425	7,639,910	8,006,676	8,393,040	8,654,425	8,819,197	8,885,187	8,863,376	8,773,714
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	1.6	5.5	12.6	23.6	38.7	58.4	82.1	107.8	132.1	153.9	168.8	177.7	201.0	222.6	244.2	270.0	297.2	322.1	341.8	355.3
Process Cooling	-	0.5	1.8	4.4	9.0	16.2	26.5	39.4	53.0	65.0	73.5	78.1	79.7	82.7	82.4	82.1	81.8	81.0	79.5	77.2	74.2
Process Heating & Boiler Fuel	-	1.3	4.9	12.3	26.1	49.4	85.8	138.1	205.7	281.1	352.9	408.6	444.1	462.7	470.7	484.7	485.4	485.7	485.3	483.3	479.0
Interior Lighting	-	0.6	2.3	5.5	11.1	20.3	34.0	52.4	74.5	97.3	118.0	133.8	144.3	152.7	157.2	157.2	157.4	155.6	153.1	150.1	146.8
Exterior Lighting	-	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	5.4	18.9	43.3	79.7	124.2	168.9	203.5	222.2	225.3	218.6	242.3	265.7	299.5	338.8	375.0	400.4	412.7	414.9	411.7	406.8
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	9.3	33.3	78.1	149.6	248.8	373.6	515.7	663.4	801.2	917.3	1,032.2	1,112.1	1,199.3	1,272.4	1,343.9	1,395.6	1,432.8	1,455.5	1,464.8	1,462.8

Industrial Sector Results by End Use *(continued)*

DSM100 Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	28,299	106,844	259,708	503,419	828,465	1,170,780	1,449,010	1,603,740	1,810,943	1,941,933	2,096,070	2,262,341	2,389,353	2,454,795	2,481,235	2,477,296	2,457,383	2,428,854	2,395,051	2,357,505
Process Cooling	-	5,096	20,888	56,556	122,398	218,884	323,509	402,941	444,717	479,855	483,085	488,379	492,798	492,671	486,977	477,020	464,218	449,324	432,665	414,416	394,732
Process Heating & Boiler Fuel	-	15,195	63,662	179,384	416,194	829,254	1,407,283	2,008,032	2,451,349	2,689,020	2,876,514	2,897,697	2,922,158	2,943,427	2,953,436	2,949,663	2,934,448	2,910,290	2,878,222	2,838,295	2,790,171
Interior Lighting	-	6,473	27,276	72,061	156,949	291,735	460,562	621,613	738,285	819,169	853,621	861,139	857,625	853,018	846,942	838,881	827,967	814,089	797,128	777,175	756,041
Exterior Lighting	-	1,180	4,949	13,917	32,132	63,801	108,877	158,134	197,633	223,529	242,248	245,515	246,168	245,619	244,106	242,536	241,294	240,358	239,753	239,300	236,729
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	62,389	233,764	546,639	954,901	1,317,020	1,518,251	1,565,151	1,735,669	1,917,609	2,200,184	2,492,695	2,681,899	2,740,137	2,713,763	2,651,445	2,579,504	2,509,149	2,445,060	2,389,390	2,343,175
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	118,631	457,382	1,128,265	2,185,993	3,549,159	4,989,261	6,204,880	7,171,393	7,940,126	8,597,586	9,081,494	9,462,989	9,664,226	9,700,018	9,640,781	9,524,727	9,380,594	9,221,683	9,053,627	8,878,353
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	2.9	10.9	26.2	50.4	82.5	118.5	151.9	175.2	212.5	246.2	273.7	305.8	335.1	356.4	371.1	379.4	383.4	384.8	384.6	383.2
Process Cooling	-	0.9	3.7	10.0	21.7	38.9	57.7	72.1	79.9	86.6	87.8	89.2	90.3	90.7	90.0	88.4	86.4	83.9	81.1	78.0	74.5
Process Heating & Boiler Fuel	-	2.5	10.3	29.2	68.2	136.0	231.4	331.2	405.6	446.3	481.5	486.8	492.7	498.0	501.3	502.3	501.2	498.7	494.7	489.3	482.4
Interior Lighting	-	1.1	4.7	12.5	27.5	51.2	81.3	110.5	132.2	148.4	157.1	159.4	159.6	159.6	159.3	158.6	157.4	155.6	153.1	150.1	146.8
Exterior Lighting	-	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	10.0	37.8	88.8	156.5	216.2	250.1	258.9	289.2	320.7	371.2	422.3	456.1	467.7	464.9	455.9	444.9	434.1	424.2	415.6	408.4
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	17.4	67.4	166.7	324.3	525.0	739.3	924.9	1,082.7	1,215.1	1,344.5	1,432.0	1,505.2	1,551.8	1,572.6	1,577.0	1,570.1	1,556.5	1,538.7	1,518.3	1,496.1

DSM100 Plus Standards

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	28,299	106,844	1,780,980	2,073,940	2,231,344	2,403,559	2,538,996	2,615,462	2,644,668	2,646,165	2,633,224	2,612,533	2,587,052	2,558,027	2,536,350	2,511,168	2,482,856	2,451,554	2,417,367	2,380,456
Process Cooling	-	5,096	20,888	491,212	499,372	509,839	519,902	526,210	527,849	526,001	521,902	516,146	508,905	500,178	489,914	478,058	464,572	449,448	432,711	414,434	394,739
Process Heating & Boiler Fuel	-	15,195	63,662	2,782,459	2,818,421	2,859,177	2,898,979	2,930,749	2,952,503	2,966,615	2,975,527	2,980,305	2,981,082	2,977,580	2,969,359	2,955,904	2,936,661	2,911,053	2,878,492	2,838,397	2,790,213
Interior Lighting	-	6,473	27,276	766,685	843,371	849,946	855,876	860,584	863,620	864,718	863,929	861,603	858,154	853,616	847,616	839,634	828,803	815,011	798,139	778,276	757,240
Exterior Lighting	-	1,180	4,949	224,850	239,781	240,187	240,204	240,382	241,100	242,504	244,335	245,957	246,643	246,125	244,642	243,104	241,899	241,005	240,446	240,044	237,521
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	62,389	233,764	2,114,214	2,313,904	2,604,398	2,899,844	3,093,780	3,159,772	3,140,266	3,079,814	3,002,333	2,918,024	2,831,463	2,745,366	2,661,886	2,582,959	2,510,332	2,445,486	2,389,553	2,343,240
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	118,631	457,382	8,160,400	8,788,788	9,294,891	9,818,364	10,190,700	10,360,305	10,384,772	10,331,672	10,239,568	10,125,341	9,996,015	9,854,924	9,714,936	9,566,063	9,409,703	9,246,827	9,078,071	8,903,409
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	2.9	10.9	179.5	259.7	285.1	316.8	345.7	367.0	380.0	388.8	392.7	394.3	394.5	393.6	394.0	393.7	393.0	391.9	390.3	388.4
Process Cooling	-	0.9	3.7	86.8	89.1	90.8	92.9	94.4	95.0	94.9	94.9	94.3	93.3	92.1	90.5	88.6	86.5	84.0	81.1	78.0	74.6
Process Heating & Boiler Fuel	-	2.5	10.3	453.6	463.6	469.5	477.7	484.4	489.6	493.2	498.1	500.7	502.6	503.8	504.0	503.3	501.6	498.8	494.7	489.3	482.4
Interior Lighting	-	1.1	4.7	131.1	151.2	152.1	153.9	155.5	156.8	157.6	159.1	159.5	159.7	159.7	159.5	158.8	157.6	155.8	153.3	150.3	147.0
Exterior Lighting	-	0.0	0.0	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	10.0	37.8	344.6	381.5	429.0	479.7	513.7	526.8	525.2	519.1	508.4	496.2	483.4	470.4	457.7	445.6	434.3	424.3	415.6	408.4
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	17.4	67.4	1,196.3	1,345.8	1,427.1	1,521.6	1,594.4	1,635.9	1,651.7	1,660.7	1,656.4	1,647.0	1,634.2	1,618.8	1,603.2	1,585.8	1,566.7	1,546.2	1,524.4	1,501.6

Table 15. Industrial Sector Results by Sub-sector

DSM25 Scenario

Industrial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	4,101	13,454	29,153	52,181	83,132	121,943	167,644	218,223	270,700	321,511	367,146	404,864	433,183	451,926	462,409	465,444	462,067	454,007	440,933	423,978
Iron and Steel	-	2,149	7,182	15,931	29,345	48,433	74,203	107,596	149,425	200,312	260,655	330,557	409,687	497,022	590,481	686,839	781,093	867,404	940,405	994,984	1,028,980
Petroleum Refining	-	835	2,737	5,930	10,609	16,885	24,731	33,924	44,018	54,358	64,163	72,665	79,265	83,648	85,803	86,017	84,589	81,867	78,278	73,973	69,242
Smelting and Refining	-	784	2,620	5,812	10,707	17,672	27,076	39,265	54,533	73,111	95,144	120,669	149,568	181,463	215,595	250,784	285,199	316,709	343,353	363,267	375,666
Cement	-	403	1,324	2,878	5,172	8,278	12,212	16,906	22,199	27,839	33,519	38,938	43,859	48,151	51,778	54,785	57,162	58,871	59,887	60,099	59,521
Misc Manufacturing	-	7,558	25,041	54,770	99,360	161,296	242,660	344,942	468,830	613,999	778,897	960,454	1,153,754	1,351,767	1,545,370	1,729,571	1,890,293	2,017,616	2,113,869	2,164,663	2,174,599
Chemicals	-	1,726	5,680	12,355	22,218	35,610	52,635	73,062	96,264	121,217	146,612	171,051	193,277	212,331	227,603	239,057	246,367	249,497	249,052	244,754	237,304
Mining	-	1,214	4,019	8,789	15,924	25,773	38,574	54,402	73,119	94,365	117,587	142,105	167,177	192,032	215,848	238,061	257,473	273,063	284,497	290,669	291,768
Total	-	18,771	62,057	135,619	245,515	397,079	594,033	837,742	1,126,610	1,455,902	1,818,089	2,203,586	2,601,450	2,999,597	3,384,405	3,747,522	4,067,619	4,327,093	4,523,347	4,633,343	4,661,058
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pulp & Paper	-	0.5	1.8	3.9	7.0	11.2	16.4	22.6	29.4	36.5	43.5	49.7	54.8	58.6	61.0	62.3	62.6	62.1	61.0	59.2	57.0
Iron and Steel	-	0.3	1.0	2.3	4.3	7.1	10.9	15.9	22.1	29.7	38.9	49.6	61.7	75.3	89.8	105.0	120.0	133.9	145.9	155.1	161.2
Petroleum Refining	-	0.1	0.5	1.0	1.9	3.0	4.4	6.0	7.9	9.7	11.5	13.1	14.3	15.1	15.5	15.5	15.3	14.8	14.1	13.3	12.5
Smelting and Refining	-	0.1	0.4	0.8	1.6	2.6	4.0	5.8	8.1	10.9	14.2	18.1	22.5	27.5	32.8	38.3	43.8	48.9	53.3	56.6	58.8
Cement	-	0.1	0.2	0.5	0.9	1.5	2.2	3.0	4.0	5.0	6.0	7.1	8.0	8.8	9.5	10.0	10.5	10.8	11.1	11.1	11.1
Misc Manufacturing	-	1.1	3.6	7.8	14.3	23.2	35.0	49.8	67.7	88.9	113.2	140.2	169.3	199.7	230.2	259.9	287.0	310.0	328.9	341.1	347.0
Chemicals	-	0.3	1.0	2.1	3.8	6.1	9.1	12.6	16.7	21.0	25.4	29.7	33.6	36.9	39.6	41.5	42.8	43.4	43.4	42.8	41.6
Mining	-	0.2	0.7	1.5	2.7	4.3	6.5	9.2	12.3	15.9	19.9	24.1	28.5	32.8	37.0	40.9	44.4	47.4	49.6	51.0	51.5
Total	-	2.8	9.1	20.0	36.5	59.0	88.4	124.9	168.2	217.6	272.7	331.5	392.7	454.5	515.4	573.6	626.5	671.3	707.2	730.4	740.7

DSM50 Scenario

Industrial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	13,800	48,711	112,003	207,647	331,087	466,787	593,529	694,731	763,598	801,159	883,952	951,969	1,042,003	1,132,753	1,218,857	1,279,630	1,311,555	1,319,562	1,312,141	1,296,760
Iron and Steel	-	7,271	26,427	63,477	125,467	219,147	349,207	516,078	712,113	916,984	1,100,284	1,253,756	1,352,644	1,418,382	1,457,617	1,506,953	1,521,695	1,527,704	1,525,235	1,514,688	1,496,508
Petroleum Refining	-	2,810	9,909	22,770	42,139	66,930	93,705	117,830	135,783	146,412	150,457	164,839	177,142	194,231	211,890	228,271	239,632	245,007	245,566	243,226	239,574
Smelting and Refining	-	2,652	9,641	23,160	45,782	79,976	127,461	188,399	259,993	334,801	401,703	457,703	493,780	517,686	532,077	550,129	555,544	557,769	556,892	553,062	546,439
Cement	-	1,356	4,804	11,114	20,783	33,543	48,120	62,674	75,657	86,115	93,440	104,442	112,967	122,105	130,840	139,419	144,625	147,076	147,302	146,137	144,245
Misc Manufacturing	-	25,460	91,101	213,442	409,486	691,046	1,058,602	1,494,810	1,958,724	2,389,200	2,735,513	3,001,833	3,158,529	3,356,146	3,494,983	3,646,814	3,773,206	3,870,419	3,927,404	3,939,271	3,911,412
Chemicals	-	5,813	20,616	47,737	89,465	144,968	209,012	273,264	329,547	372,155	398,899	436,829	464,892	501,859	535,518	567,546	589,923	601,209	602,869	597,805	588,817
Mining	-	4,094	14,641	34,270	65,361	108,800	162,995	223,920	285,835	341,885	385,874	428,696	457,502	487,498	510,998	535,052	550,168	558,460	560,357	557,046	549,958
Total	-	63,256	225,850	527,974	1,006,130	1,675,498	2,515,888	3,470,505	4,452,382	5,351,151	6,067,329	6,732,051	7,169,425	7,639,910	8,006,676	8,393,040	8,654,425	8,819,197	8,885,187	8,863,376	8,773,714
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pulp & Paper	-	1.8	6.5	15.0	27.9	44.4	62.5	79.2	92.4	101.2	106.4	118.9	129.2	142.6	156.3	169.1	178.2	183.3	185.1	184.8	183.4
Iron and Steel	-	1.0	3.8	9.2	18.4	32.2	51.5	76.4	106.0	137.1	165.8	190.3	206.5	217.6	224.8	233.6	236.7	238.5	239.1	238.4	236.4
Petroleum Refining	-	0.5	1.7	4.0	7.5	11.9	16.6	20.9	24.0	25.9	26.7	29.5	32.0	35.3	38.9	42.1	44.4	45.6	45.9	45.6	45.1
Smelting and Refining	-	0.4	1.4	3.4	6.7	11.8	18.8	27.9	38.7	50.1	60.5	69.4	75.4	79.4	82.0	85.3	86.4	87.1	87.3	87.0	86.3
Cement	-	0.2	0.8	2.0	3.7	6.0	8.6	11.2	13.5	15.4	16.8	19.0	20.6	22.5	24.2	25.9	27.0	27.6	27.7	27.6	27.3
Misc Manufacturing	-	3.6	13.0	30.6	59.0	99.5	152.4	215.8	284.5	350.4	407.5	456.0	488.1	528.1	560.4	590.9	618.0	641.2	659.1	670.3	674.7
Chemicals	-	1.0	3.5	8.2	15.4	24.9	35.9	46.8	56.3	63.5	68.3	75.7	81.3	88.6	95.5	101.9	106.5	109.2	110.1	109.8	108.8
Mining	-	0.7	2.4	5.7	11.0	18.2	27.3	37.5	48.0	57.5	65.4	73.5	79.2	85.2	90.2	95.1	98.3	100.4	101.3	101.4	100.7
Total	-	9.3	33.3	78.1	149.6	248.8	373.6	515.7	663.4	801.2	917.3	1,032.2	1,112.1	1,199.3	1,272.4	1,343.9	1,395.6	1,432.8	1,455.5	1,464.8	1,462.8

Industrial Sector Results by Sub-sector *(continued)*

DSM100 Scenario

Industrial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	25,829	97,791	232,954	422,748	622,157	782,428	883,531	1,000,851	1,110,473	1,237,320	1,356,294	1,438,800	1,471,342	1,467,655	1,446,685	1,418,695	1,388,999	1,359,904	1,332,432	1,307,001
Iron and Steel	-	13,703	54,380	140,847	292,902	520,296	803,644	1,078,555	1,291,341	1,420,198	1,529,382	1,570,378	1,602,708	1,620,230	1,623,044	1,615,361	1,600,866	1,582,105	1,560,183	1,535,438	1,507,855
Petroleum Refining	-	5,259	19,886	47,275	85,269	123,929	152,896	168,830	189,344	209,081	232,941	256,349	272,036	277,481	275,805	270,840	264,664	258,276	252,102	246,338	241,073
Smelting and Refining	-	4,999	19,841	51,395	106,903	189,946	293,434	393,794	471,419	518,290	558,233	573,242	585,089	591,521	592,573	589,788	584,511	577,674	569,681	560,656	550,593
Cement	-	2,541	9,678	23,318	43,114	65,326	85,398	100,226	115,486	127,504	141,188	152,200	159,709	162,529	162,002	159,832	156,986	153,945	150,913	147,977	145,169
Misc Manufacturing	-	47,726	184,576	458,812	906,726	1,514,556	2,181,834	2,755,769	3,161,408	3,514,952	3,767,331	3,965,615	4,142,253	4,255,147	4,294,397	4,288,302	4,250,245	4,194,819	4,129,147	4,056,342	3,977,516
Chemicals	-	10,892	41,547	100,352	186,488	283,725	369,382	428,323	483,986	534,054	583,642	629,288	661,373	674,104	672,098	662,683	649,852	635,813	621,542	607,478	593,812
Mining	-	7,682	29,685	73,311	141,843	229,224	320,246	395,852	457,558	505,574	547,549	578,128	601,021	611,871	612,445	607,290	598,907	588,962	578,210	566,965	555,335
Total	-	118,631	457,382	1,128,265	2,185,993	3,549,159	4,989,261	6,204,880	7,171,393	7,940,126	8,597,586	9,081,494	9,462,989	9,664,226	9,700,018	9,640,781	9,524,727	9,380,594	9,221,683	9,053,627	8,878,353

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	3.4	13.0	31.1	56.5	82.7	103.4	116.4	132.9	148.5	168.1	185.5	197.9	203.4	203.9	201.9	198.9	195.5	192.0	188.7	185.7
Iron and Steel	-	2.0	7.9	20.5	43.0	76.7	119.0	160.6	193.4	213.7	232.7	239.9	245.9	249.7	251.3	251.2	249.9	247.9	245.4	242.3	238.7
Petroleum Refining	-	0.9	3.5	8.3	15.1	21.8	26.9	29.6	33.5	37.2	42.0	46.6	49.7	51.0	51.0	50.3	49.4	48.3	47.4	46.4	45.6
Smelting and Refining	-	0.7	2.9	7.5	15.7	28.0	43.4	58.6	70.6	78.0	84.9	87.6	89.8	91.2	91.7	91.7	91.3	90.5	89.6	88.5	87.2
Cement	-	0.4	1.7	4.1	7.7	11.6	15.2	17.8	20.7	22.9	25.7	27.9	29.4	30.1	30.1	29.9	29.4	29.0	28.5	28.0	27.6
Misc Manufacturing	-	6.8	26.4	65.8	130.5	217.5	315.2	403.1	471.6	536.4	593.5	632.0	668.7	696.8	713.7	722.3	724.0	721.2	715.5	707.8	698.7
Chemicals	-	1.9	7.1	17.2	32.0	48.4	62.8	72.6	82.8	92.2	102.5	111.4	117.9	121.0	121.4	120.5	118.8	116.8	114.6	112.4	110.3
Mining	-	1.3	4.9	12.2	23.8	38.2	53.4	66.2	77.3	86.3	95.1	101.2	105.9	108.6	109.5	109.3	108.5	107.2	105.7	104.1	102.4
Total	-	17.4	67.4	166.7	324.3	525.0	739.3	924.9	1,082.7	1,215.1	1,344.5	1,432.0	1,505.2	1,551.8	1,572.6	1,577.0	1,570.1	1,556.5	1,538.7	1,518.3	1,496.1

DSM100 Plus Standards

Industrial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	25,829	97,791	1,174,354	1,281,489	1,400,779	1,522,766	1,605,219	1,636,933	1,634,037	1,613,980	1,586,286	1,555,038	1,522,020	1,488,229	1,455,262	1,422,869	1,391,634	1,362,042	1,334,456	1,309,054
Iron and Steel	-	13,703	54,380	1,473,678	1,523,096	1,571,730	1,620,875	1,656,139	1,673,500	1,678,171	1,675,870	1,669,659	1,660,744	1,649,519	1,636,091	1,620,821	1,603,290	1,583,430	1,561,139	1,536,287	1,508,695
Petroleum Refining	-	5,259	19,886	223,289	242,594	266,172	290,205	306,217	312,016	310,889	306,351	300,307	293,569	286,494	279,286	272,203	265,275	258,629	252,372	246,586	241,321
Smelting and Refining	-	4,999	19,841	537,755	555,841	573,645	591,636	604,550	610,917	612,642	611,819	609,566	606,325	602,241	597,351	591,790	585,403	578,164	570,037	560,973	550,907
Cement	-	2,541	9,678	135,013	144,259	155,559	167,056	174,804	177,784	177,528	175,667	173,081	170,141	167,005	163,762	160,519	157,286	154,112	151,036	148,088	145,280
Misc Manufacturing	-	47,726	184,576	3,535,608	3,879,237	4,085,755	4,303,694	4,466,095	4,548,874	4,571,541	4,560,158	4,530,666	4,490,411	4,442,469	4,388,166	4,336,534	4,279,064	4,216,175	4,148,093	4,074,963	3,996,680
Chemicals	-	10,892	41,547	559,457	604,516	651,280	699,120	731,563	744,114	742,929	734,761	723,322	710,201	696,083	681,337	666,685	651,880	637,138	622,638	608,525	594,877
Mining	-	7,682	29,685	521,247	557,756	589,970	623,011	646,112	656,167	657,035	653,066	646,681	638,912	630,184	620,702	611,122	600,996	590,422	579,470	568,193	556,595
Total	-	118,631	457,382	8,160,400	8,788,788	9,294,891	9,818,364	10,190,700	10,360,305	10,384,772	10,331,672	10,239,568	10,125,341	9,996,015	9,854,924	9,714,936	9,566,063	9,409,703	9,246,827	9,078,071	8,903,409

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	3.4	13.0	152.1	170.4	186.5	204.2	216.7	222.3	222.8	221.9	219.1	215.7	211.9	207.9	203.9	200.0	196.2	192.5	189.1	186.0
Iron and Steel	-	2.0	7.9	216.8	227.3	234.3	242.7	249.0	252.8	254.4	256.0	256.2	255.8	255.1	253.9	252.4	250.6	248.3	245.6	242.5	238.9
Petroleum Refining	-	0.9	3.5	38.6	42.8	47.1	51.7	54.9	56.2	56.2	55.9	55.0	54.0	52.9	51.8	50.7	49.5	48.5	47.4	46.5	45.6
Smelting and Refining	-	0.7	2.9	79.1	83.0	85.5	88.6	90.9	92.3	92.9	93.5	93.5	93.4	93.1	92.7	92.2	91.5	90.7	89.7	88.5	87.2
Cement	-	0.4	1.7	23.7	25.7	27.8	30.0	31.5	32.2	32.3	32.2	31.9	31.5	31.0	30.5	30.0	29.5	29.0	28.5	28.1	27.6
Misc Manufacturing	-	6.8	26.4	506.9	597.9	633.2	676.0	711.5	734.6	746.3	754.4	755.7	754.2	750.9	746.1	741.6	735.9	729.1	721.4	712.6	703.0
Chemicals	-	1.9	7.1	93.4	103.9	112.2	121.5	128.1	131.2	131.6	131.3	130.0	128.2	126.2	124.0	121.8	119.5	117.2	114.9	112.7	110.6
Mining	-	1.3	4.9	85.9	94.8	100.5	106.9	111.8	114.3	115.1	115.5	115.0	114.2	113.1	111.9	110.6	109.2	107.7	106.1	104.4	102.7
Total	-	17.4	67.4	1,196.3	1,345.8	1,427.1	1,521.6	1,594.4	1,635.9	1,651.7	1,660.7	1,656.4	1,647.0	1,634.2	1,618.8	1,603.2	1,585.8	1,566.7	1,546.2	1,524.4	1,501.6

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Electricity Demand in Ontario – Assessing the Conservation and Demand Management (CDM) Potential

Prepared for:

Ontario Power Authority

Revised November 2005

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1. Introduction

The objective of this assessment is to provide the Ontario Power Authority (OPA) with guidance on the role of energy conservation within its Integrated Power System Plan (IPSP). Specifically, the OPA seeks recommendations pertinent to the development of conservation targets through to the year 2025 within the context of already existing efficiency goals and overall supply mix objectives. Our terms of reference further specified that the efficiency potential be assessed relative to a particular forecast of electricity demand produced by the Independent Electricity System Operator in which the total demand for electricity in Ontario grows from its current level of 144 TW.hours per year to 170 TW.hours per year by 2025.[1]

Unlike supply side resources like coal or wind, the demand side resource has no physical limit; it grows when electricity using activity grows and it grows whenever someone devises a new way of getting more value for less electricity, either through increased electricity productivity (more economic value per kilowatt-hour) or through the invention of techniques and technologies that use electricity more efficiently. This makes the determination of the electricity efficiency potential inherently complex and information-intensive. During the period between the demise of Ontario Hydro in the early 1990's and the establishment of the Ontario Power Authority, there has been no agency with a mandate to conduct integrated resource planning with its associated need for long term electricity demand forecasting or scenario analysis. As a result of this hiatus, the databases and analytical capacity to support such work has atrophied, exacerbating the challenge of producing the rapid assessment of efficiency potential required by the OPA.

We have looked at the potential for electricity efficiency in Ontario from three different perspectives. First, we have made a broad assessment of the current technical and economic potential for efficiency improvement, as compared with the IESO forecast. Second, we have reviewed assessments and CDM program results from other jurisdictions and estimated the impact that similar experience would have in Ontario. And finally, we have employed ICF's Energy Efficiency Potential Model (EEPM) to provide estimates of technical, economic, and achievable energy savings potential.

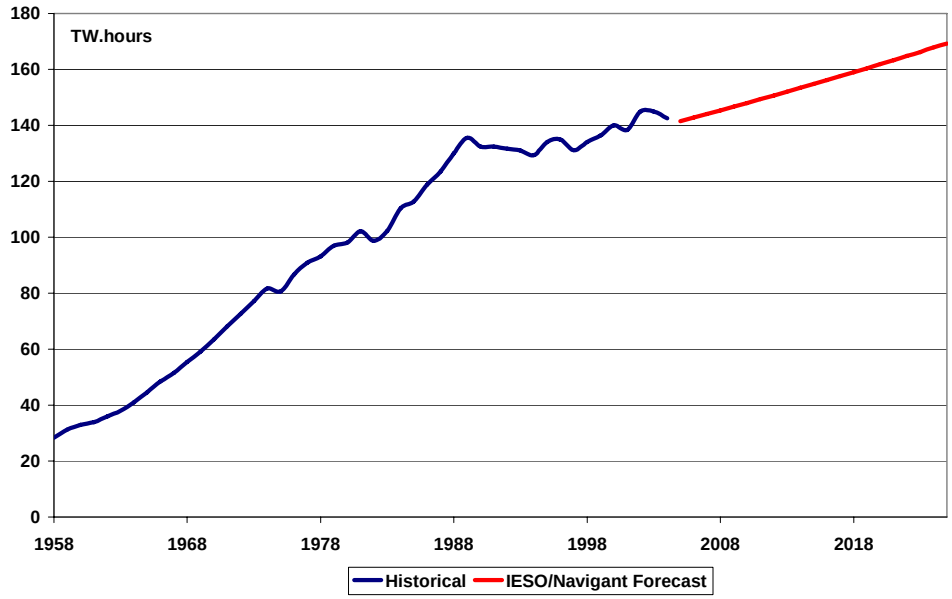
[1] A Terawatt-hour (TW.hour) is a billion kilowatt-hours. Other units of electricity used in this report include the Megawatt-hour (MW.h), which equals a thousand kilowatt-hours, and the Gigawatt-hour (GW.hour), which equals a million kilowatt-hours.

2. The Reference Forecast

The reference forecast of electricity demand specified by the Ontario Power Authority for use in this study projects that the demand for electricity in Ontario will grow to 170 TW.hours by 2015 and 186 TW.hours in 2025. These figures include the transmission and distribution power losses that occur between the power plants and the end uses – the forecast consumer demand for electricity at the point of end use is about nine percent lower or 155 TW.hours in 2015 and 170 TW.hours by 2025.[2] The forecast was produced by Navigant Consulting for Hydro One in a recent study of electricity costs in Ontario, and it is a simple extrapolation to the year 2025 of a forecast to the year 2015 produced by the Independent Electricity System Operator (IESO).[3] The IESO forecast itself is a single line projection of electricity demand and is driven by forecast growth in housing starts and the labour force. The forecast end use demand for electricity is compared with the historical trend line in Figure 1.

Figure 1.

Electricity End Use in Ontario: Historical vs. IESO/Navigant Forecast



The forecast illustrated in Figure 1 is a so-called "business-as-usual" forecast. It is an illustration of what would happen to the future demand for electricity in the absence of any new policies and programs to promote conservation and electricity efficiency, and in the absence of any significant departure from the recent, historical relationship between growth in Ontario's labour force and housing stock and growth in the demand for electricity.

[2] As the focus of this study is the potential for impacting the demand for electricity at the point of end use, references in this report to future levels of electricity demand or electricity savings are to demand and savings at the point of end use, unless specially noted otherwise.

[3] Navigant Consulting Ltd., "Avoided Cost Analysis for the Evaluation of CDM Measures Presented to Hydro One Networks Inc.", June 14, 2005. The Navigant forecast is an extrapolation the "Median Growth Scenario" in the IESO 10-Year Outlook: Ontario Demand Forecast from January 2005 to December 2014 (March 31, 2004).

Our task was to estimate the potential for electricity demand side measures to reduce the future demand for electricity relative to this forecast. However, the IESO/Navigant forecast is highly aggregated; it contains no breakdown by sector (e.g. residential, commercial and industrial electricity use) and it contains no breakdown by end use (e.g. appliances, lights, motors and equipment, space heat, water heat, etc). To build up an estimate of the potential for electricity efficiency improvements relative to the IESO/Navigant forecast, we first need to know how much of the forecast demand for electricity occurs in each sector and end use. For example, before we can calculate the potential for more efficient lighting systems to reduce the use of electricity for lighting in commercial buildings, we first need to know how much electricity is forecast for this particular sector/end use combination.

To develop a plausible breakdown of the IESO/Navigant forecast electricity demand by sector and by end use, we started with a recent factor analysis of historical patterns of electricity use in Ontario.[4] This analysis was combined with the labour force and housing stock growth indices used to drive the IESO/Navigant forecast.

For the residential sector, the total housing starts used as a driver in the IESO forecast agree closely with the housing projections used by NRCan. Because the NRCan projections include a breakdown by dwelling type (single detached, single attached, apartments) we adopted the NRCan housing projection to drive residential electricity demand. In this projection, household growth averages 1.6% percent per year over the forecast period, with corresponding population growth of 1.1 percent per year. By 2025, Ontario's population reaches 15.5 million with 6.5 million households, compared to 4.75 million today. We assumed that for each end use, electricity per household would continue to follow the trend exhibited over the 1990-2003 period. During this period, electricity use per household declined for some end uses (e.g. refrigerators), and for these end uses electricity per household was assumed to continue to decline at its average historic rate for the 1990-2003 period. The resulting electricity use per household for each end use was checked for reasonableness to ensure that the levels projected by 2025 stayed within the bounds of existing technological capability.

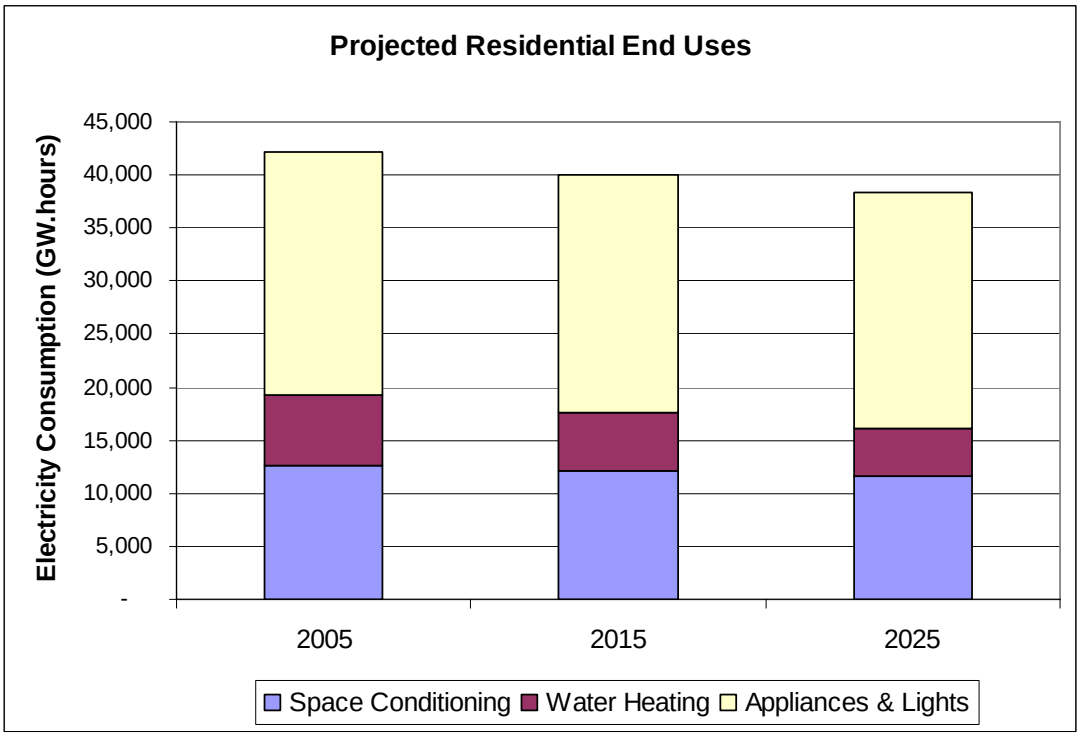
The resulting projection of electricity end uses in the residential sector is illustrated in Figure 2. The continuing improvement in efficiency offsets household growth, with total residential electricity use continuing to decline, as it has over the 1990-2003 period. In this projection, total residential electricity use in 2025 is 38.3 TW.hours.

Note that the consumption of electricity in Ontario's residential sector is largely dependent on the number of households using electricity for space and/or water heating. There is a slight decline in the percent of households using electricity for water heating in the end use forecast developed here, but by 2025 space heating still accounts for 25% of total residential electricity use and water heating another 12%. An estimated 650,000 households in Ontario are heated with electric baseboard heaters, and over 1.5 million households use electricity for domestic

[4] ICF Consulting, "Factor Analysis of Ontario Electricity Use – 1990-2003", prepared for Ontario Power Authority, revised November 2005. Available at http://www.powerauthority.on.ca/Storage/14/995_Factor_Analysis_of_Ontario_Electricity_Use_1990-2003.pdf.

water heating. Should circumstances or policy lead to a change in electricity's share of either the space or water heating market in Ontario, the resulting impact on total residential electricity use could be larger than the likely effect of efficiency improvements on the other end uses.

Figure 2.

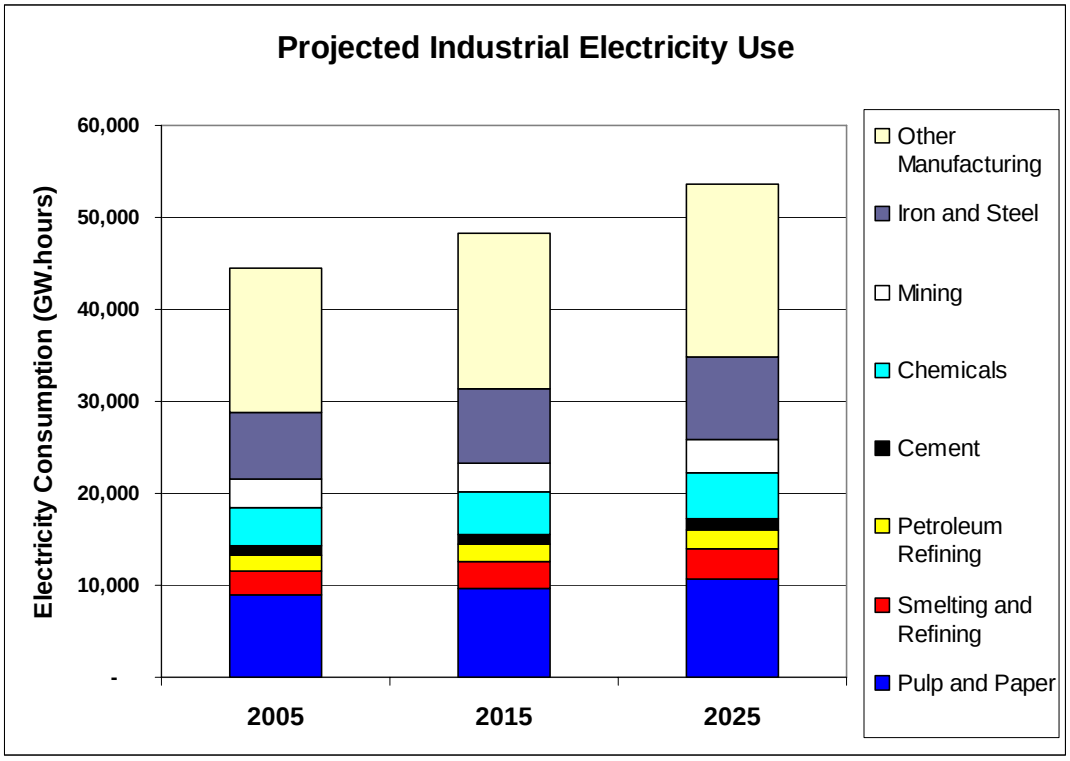


For the service sector, we projected future electricity use as the product of floor area and electricity intensity (per unit floor area) for each building type and end use. The historic relationship between floor area and employment growth was used to project future floor area based on the employment growth forecast obtained from the IESO. Electricity intensities within the service sector did not change significantly over the 1990-2003 period and so the 2003 intensities were combined with the floor area projection to develop a disaggregated profile for forecast electricity use in the service sector. Strong growth in this sector results in correspondingly strong electricity demand growth, with both total floor area and electricity consumption up by more than 35% by 2025. Forecast electricity use in the service sector reaches 75 TW.hours by 2025, representing fully 44% of total forecast electricity consumption. Available Ontario data include only four specific end uses for the commercial sector with two additional broad "auxiliary" end uses. To add greater specificity to our results, we have estimated what percentages of these auxiliary categories may fall into more specific end uses.

For the industrial sector, we projected electricity demand by assuming a continuation of the historical relation between demand and the employment index used to drive the IESO forecast. The historical data would not support a projection at the individual industry level, so electricity demand was projected at the sector level with industrial structure held constant. The resulting forecast of industrial electricity consumption is illustrated in Figure 3. The most notable aspect of industrial electricity use in Ontario, and of the forecast of future industrial electricity use, is

the extent to which demand is dominated by the electricity-intensive industries: pulp and paper, metals smelting, petroleum refining, cement, industrial chemicals and mining. This group accounts for fully 62% of industrial electricity use in Ontario. In the forecast presented here, these industries grow at the same rate as all industry, adding more than 6,000 GW.hours of demand to the forecast by 2025. In the event that the share of Ontario's industrial GDP from these industries declines over the forecast period, or that these industries grow their output faster than their electricity consumption, the impact on total industrial electricity demand could be large relative to the potential for electricity efficiency improvements.

Figure 3.



The sector-based projections described above add up to a total forecast for electricity that is in good agreement with single line IESO/Navigant forecast and form the basis for the conservation and demand management analyses described below.[5] This is only one of any number of possible disaggregations of the IESO/Navigant forecast that could be generated; it is based on the same underlying household and employment indices used to drive the IESO forecast, combined with a continuation of historical trends in the activity drivers (households, floor area of commercial building space, industrial output) and electricity intensities. As illustrated in Figure 4, the end use demand for electricity (i.e. net of transmission and distribution losses) grows to 170 TW.hours by 2025.

[5] Appendix A contains detailes of the base forecast disaggregation.

The growth rate reflected in the IESO/Navigant forecast is 0.9 percent per year. The exercise of creating a sector and end-use based disaggregation of the forecast did reveal some areas where the future demand for electricity is particularly sensitive to changes in the underlying drivers:

- ***Residential space and water heating.*** In 2025, space and water heating account for 9.4 TW.hours and 4.6 TW.hours, respectively, of the forecast demand. Changes in technology, relative prices or policy could significantly affect this projected demand. Our disaggregation of the forecast also assumed continued rapid growth in residential air conditioning (0.72% per year).
- ***Commercial Buildings.*** With the assumptions used here, fully 80% of the electricity demand growth in the IESO/Navigant forecast is attributed to the commercial buildings sector – over 20 TW.hours by 2025. It is driven by continued strong relative growth in the services sector of the economy, growth in commercial building floor area according to historical trends, and no improvement in commercial building electricity intensities. If improvements in the efficiency of commercial building electricity use outpace the development of new electricity applications in these buildings, electricity growth could be significantly lower than forecast here.
- ***Electricity Intensive Industries***. The electricity-intensive industries that account for more than 60% of industrial electricity use in Ontario are in a state of transition. Their relative share of total economic activity has declined overall, and within these industries output is generally growing faster than electricity consumption. In the disaggregation of the IESO/Navigant forecast developed here, these industries hold their 2003 shares of the Ontario industrial output and their demand for electricity follows its historical pattern. As a result, the forecast demand for electricity from these industries grows by more than six TW.hours, but lower or even negative growth in electricity demand from these industries is well within the range of plausible scenarios.
- ***Cogeneration.*** There is no allowance for the growth of cogeneration in our calibration of the IESO/Navigant forecast. This is a potentially dynamic growth area over the life of the forecast and could significantly affect the demand for grid electricity. A study for the Ontario government published in 2000 estimated the technical potential for cogeneration to be over 16,500 MW by 2020.[6] The base case estimate of economic potential equaled 3,800 MW by 2010. This estimate was based on what would now be viewed as a low wholesale cost of electricity ($43/MWh in 2010). Assuming a 75% capacity factor, 3,800 MW of co-generation capacity could displace 25 TW.hours annually. Even at this level, the contribution from cogeneration would be lower than is common practice in many European countries.[7]

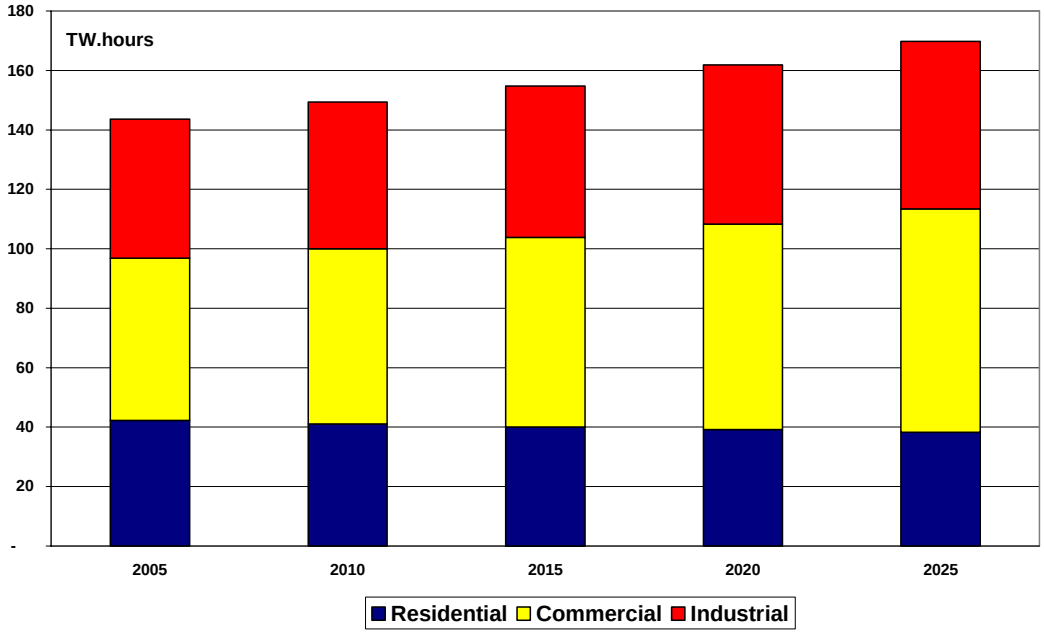
[6] Hagler Bailly, "Potential for Cogeneration in Ontario - Final Report" prepared for the Ministry of Energy, Science and Technology, the Ministry of Natural Resources, and the Ministry of Economic Development and Trade, August, 2000.

[7] Energy for Sustainable Development (ESD) Ltd., "The Future of CHP in the European Market - The European Cogeneration Study", May 2001.

We did not conduct a risk analysis of the forecast, but the demand for electricity in Ontario is clearly in a state of transition. While the IESO forecast growth rate of 0.9 percent per year is low by the standards of the 1970's and 1980's, it is significantly higher than the 0.5 percent year average of the period since 1990. The forecast demand could prove low if the electricity-intensive industries grow faster than the rest of the economy, or if electricity's market share of space and water heating increases, or if the rate of new commercial building construction accelerates relative to the trend of the past fifteen years, but these circumstances represent reversals of recent trends. If recent trends continue, then the risk of the forecast being too high is more likely. Of the 170 TW.hours of electricity demand in the forecast for 2025, at least 75 TW.hours are vulnerable to the areas of uncertainty described above.

Figure 4.

Projected Electricity Use by Sector



3. Estimating the CDM Potential

Ideally, an estimate of the potential for electricity efficiency improvement to reduce the demand from the forecast level would be based on an integrated analysis of the future demand for electricity that included a detailed breakdown of electricity use by subsector and end use. Unfortunately, in recent years there has been very little work done on tracking electricity use in Ontario at such a detailed level. We have developed one plausible breakdown of the IESO/Navigant forecast, but there are any number of alternative breakdowns that would include more or less demand from the various subsectors and end uses that make up the total demand for electricity in Ontario. The potential for using electricity more efficiently varies over a wide range from one end use to the next and from one subsector of the economy to the next, and so the total size of the CDM resource base will also vary depending on the mix of electricity using activities that is assumed in the forecast. In the assessments of the CDM potential described below, we have used the IESO/Navigant forecast and we have used our disaggregation of that forecast by sector and by end use. Our CDM potential assessments are therefore only as relevant as the accuracy of the forecast and of our disaggregation of the future demand into sectors and end use categories.

The CDM potential also depends on the extent to which electricity efficient technologies are already being used in Ontario (these are the market saturations of the various technologies) and the extent to which electricity efficient technologies are already being chosen when new equipment is purchased or existing equipment is replaced (these are the market shares of the various technologies). To the extent efficient technologies are already deployed in Ontario the potential for CDM programs will be less than if those technologies are not yet in place. Similarly, if electricity efficient technologies are already taking large market shares in Ontario, even in the absence of CDM programs, then the potential for CDM programs to increase market shares will be that much less.

In the face of these data gaps and resulting uncertainties, we have taken three different approaches to assessing the CDM potential in Ontario. First, we have estimated the technical and economic potential for efficiency improvement against the existing level and pattern of electricity use in Ontario. This yields a somewhat theoretical potential that does not include any consideration for what is practically achievable over time. It does however provide an indication of the upper limit to what real CDM programs might achieve, given the current state and costs of technology, our assumed breakdown of Ontario electricity use, and the anticipated avoided costs of new generation. Second, we have reviewed CDM assessments and experience in other jurisdictions and calculated what the corresponding achievable savings would be in Ontario if these assessments and experiences were emulated here. Third, we have applied a stock turnover accounting model to estimate the achievable CDM potential over time given an assumed set of base market shares and different levels of CDM program incentives.

4. The Technical and Economic Potential

A list of approximately 300 energy efficiency measures to be considered for the residential, commercial, and industrial sectors has been compiled for ICF's EEPM model (described in more detail in Section 6 below). These measures represent both replace-on-fail and retrofit options for all major end uses. The measures have been screened for applicability and feasibility for potential energy efficiency programs. Measure data stored for each measure in the EEPM database were cross-checked against existing Ontario and Canadian sources. In evaluating each measure, a number of elements were considered including incremental capital and installation costs, O&M costs, measure life, and per unit energy and demand savings. Differing assumptions about the specifics of these elements (i.e. hours of operation) will change the resulting economic assessment. Based on our review of other Canadian energy efficiency potential studies and CDM analyses, the measure cost and savings data used in EEPM are consistent with the Ontario climate and market.[8]

The **technical potential** quantifies the savings that could be realized if energy efficiency measures were applied in all technically feasible instances, regardless of cost. As is often the case, we estimate technical potential assuming that this change-out occurs immediately. Technical potential is therefore useful as a broad gauge of the economy's inefficiency in the territory of interest. The technical potential in this analysis is narrowly defined to include the potential for improving the efficiency of electricity use without changing the technology type. Substituting other fuels for electricity is also outside the scope of the definition of CDM used here. (This last point is particularly important to bear in mind when considering electricity demand in the residential sector, where space and water heating account for 14 TW.hours of electricity consumption, about 10% of all the electricity used in the province).

The **economic potential** is the subset of technical potential that is cost-effective from a Total Cost Test (TCT) perspective. As for technical potential, economic potential assumes that all relevant energy efficiency improvements occur instantaneously.

In determining the measures to be included in the economic potential, end use savings factors are calculated by first determining the amount of building stock, if any, for a particular building type that can be affected by a particular measure. For instance, a refrigeration measure would be applicable to a grocery or warehouse building, but not to an office building. Then, each measure for a specific end use that had a benefit/cost ratio of 1.0 or greater was aggregated with others in that end use to arrive at an end use level savings factor. For instance, if two cost-effective measures exist for a lighting end use, each with savings potential of 25%, the measures are assumed to be implemented in series so that the overall savings due to application of both measures would be 43.7%. Finally the end use savings factors for all cost effective measures were applied to their respective end use loads to determine the economic potential for savings.

[8] Appendix B contains descriptions of the measures in the EEP database.

The economic screening process uses what is known as the Technical Cost Test (TCT), similar to the TRC test,[9] which compares the incremental measure cost with savings valued at utility avoided costs. Our source for these data was the recent Navigant Consulting study on avoided costs presented to Hydro One Networks.[10] The screening also compared the incremental measure cost for each measure with the present value of a future stream of estimated average retail prices (for the Participant Cost Test). Measures with a benefit/cost ratio of 1.0 or greater for the Participant Cost Test were considered eligible for adoption by consumers in developing estimates of naturally occurring energy efficiency. Measures passing the TCT became part of the set of efficiency measures considered in developing estimates of achievable potential.

The tables and figures below show 2004 electricity sales and estimated peak demand for each sector along with our estimates of instantaneous technical and economic potential based on that load.

As noted above, estimates of technical and economic potential do not take into consideration the practical, achievable potential for CDM, and they are made relative to the current (i.e. year 2004) demand, not the forecast demand. The economic potential does however indicate that there is an economically cost effective scope for improving the efficiency of electricity use in Ontario by about 21%, with considerably more technical potential that would be economic at higher avoided costs. Given that the forecast demand for electricity is 170 TW.hours in 2025, the economic potential estimate suggests an economic CDM potential in the range of 35 TW.hours, relative to the 2025 forecast. It is interesting to note that the economic potential is about equal to the amount of growth in the IESO/Navigant forecast, suggesting that aggressive CDM programs in Ontario could largely offset growth in the demand for electricity, as forecast.

Table 1. Technical and Economic Potential

	TW.hours			GW		
Forecast	2004 Load	Technical Potential	Economic Potential	2004 Load	Technical Potential	Economic Potential
Residential	46.9	11.5	9.6	6.9	2.9	1.8
Commercial	52.9	16.6	12.4	10.2	3.9	2.3
Industrial	41.9	8.4	7.5	7.4	1.5	1.2
Total	141.7	36.6	29.6	24.5	8.2	5.2

[9] The Technical Cost Test essentially compares the incremental installation cost of a measure with the avoided cost and differs from the Total Resource Cost Test in that at this stage, program administrative costs are not considered.
[10] Navigant Consulting, *Avoided Cost Analysis for the Evaluation of CDM Measures*. June 2005.

Figure 5. 2004 Load, Technical & Economic Potential by Sector (Electricity Sales)

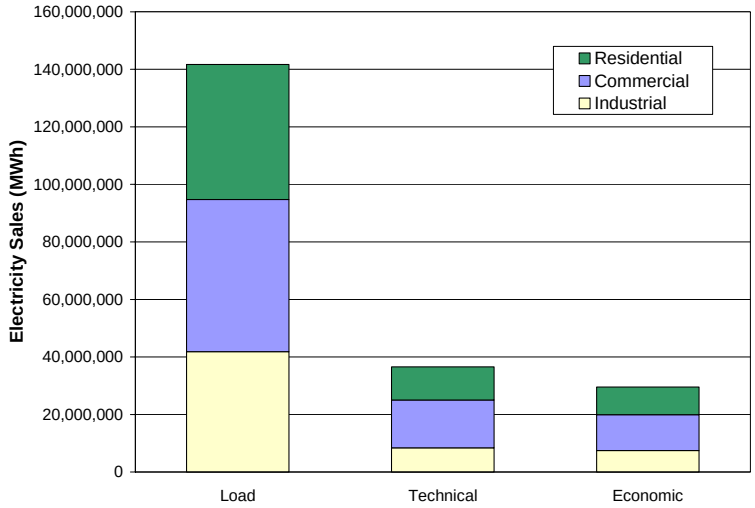
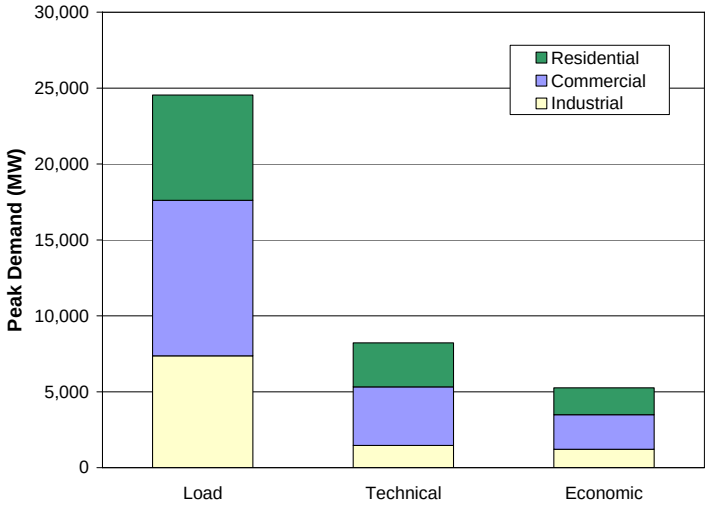


Figure 6. 2004 Load, Technical & Economic Potential by Sector (Peak Demand)



5. Achievable CDM – Experience Based Assessment

Our second approach to assessing the CDM potential in Ontario was to review both assessments and actual experience in other jurisdictions. Dozens of estimates of energy efficiency potential have been prepared for jurisdictions in North America over the past decade, and this information can be placed in context by also examining the results of actual CDM program implementation. This section briefly summarizes estimates of potential and program impacts gathered from a wide range of sources. Where the data permit, estimates of potential and program impact expressed in relative terms (percentage reduction in energy or peak) are applied to our disaggregation of the IESO/Navigant forecast to illustrate the magnitude of savings if such reductions were achieved in Ontario.

In a number of cases the time horizon for which estimates of CDM potential were prepared in these other studies differs from the 2025 time horizon of interest to the OPA. In cases in which the forecast horizons used for these other studies extended for less than the 20-year horizon used here, no attempt was made to extrapolate the results. Absent a much more detailed understanding of the methods underlying these studies such extrapolation would create an unrealistic comparison with the estimates that we have prepared using the accounting method described above. Where only a single year estimate of potential was reported (e.g. total achievable potential by the year 2015), relative savings for preceding years were estimated using linear extrapolation. Although the adoption of energy efficiency measures typically follows an S-shaped path, we believe the linear extrapolation used here is sufficient for intra-year comparisons.

Estimates of Efficiency Potential

We have examined the results of twenty one relatively recent estimates of efficiency potential from the US and Canada. The studies are summarized in the following table.

Table 2. Index of Reviewed Energy Efficiency Potential Studies

Organization Name and Author	Title	Year	Jurisdiction	Sectors Considered
ACEEE Margaret Suozzo, Steven Nadel, Jeff Harris, Tom Eckman	Selecting Targets for New Market Transformation Initiatives in the Northwest	1998	Oregon, Washington	Residential, Commercial & Industrial
ACEEE R. Neal Elliott	Electricity Consumption and the Potential for Electric Energy Savings in the Manufacturing Sector	1994	U.S.	Manufacturing
Optimal Energy John Plunkett Phil Mosenthal Chris Neme	Vermont Department of Public Service Electric and Economic Impacts of Maximum Achievable Statewide Efficiency Savings 2003-2012	2002	Vermont	Residential, Commercial & Industrial
RLW Analytics, Inc.	The Remaining Electric Energy Efficiency Opportunities in Massachusetts Final Report	2001	Mass.	Residential, Commercial & Industrial
Kema-Xenergy, Inc. Fred Coito & Mike Rufo	California Statewide Commercial Sector Energy Efficiency Potential Study	2002	California	Commercial
Kema-Xenergy, Inc. Fred Coito & Mike Rufo	California Statewide Residential Sector Energy Efficiency Potential Study	2003	California	Residential
BC Hydro	BC Hydro Conservation Potential Review 2002 Summary Report	2003	British Columbia	Residential, Commercial & Industrial
Ecotope, Inc. ACEEE, and Tellus Institute Shelly Borrelli, David Baylon	Energy Efficiency and Conservation Measure Resource Assessment for the Residential, Commercial, Industrial and Agricultural Sectors	2003	Oregon	Residential, Commercial & Industrial
GDS Associates and Quantum Consulting Jeff Schlegel, Richard Spellman	Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region - Final Report	2004	Connecticut	Residential, Commercial & Industrial

Organization Name and Author	Title	Year	Jurisdiction	Sectors Considered
Southwest Energy Efficiency Project Howard Geller, Neal Elliott, Toru Kubo, Steve Nabel, Anna Shipley	The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest	2002	Six states in the SW US	Residential, Commercial & Industrial
New York State Energy Research and Development Authority (NYSERDA)	Energy Efficiency and Renewable Energy Resource Development Potential in New York State	2003	New York	Residential, Commercial & Industrial
Oak Ridge National Laboratory (ORNL) Stan W. Hadley	The Potential for Energy Efficiency in the State of Iowa	2001	Iowa	Residential, Commercial & Industrial
Tellus Institute	An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah	2001	Utah	Residential, Commercial, & Industrial
Richard Brown	Estimates of the Achievable Potential for Energy Efficiency Improvements in U.S. Residences	1993	U.S.	Residential
Synapse Energy Economics	Repowering the Midwest: The Clean Energy Development Plan for the Heartland	2001	Illinois, Indiana, Iowa, Michigan, Minnesota, Nebraska, North Dakota, Ohio, South Dakota	Residential, Commercial & Industrial
ACEEE Marshall Goldberg, Martin Kushler, Steven Nadel	Energy Efficiency and Economic Development in Illinois	1998	Illinois	Residential, Commercial & Industrial
KEMA	New Jersey Energy Efficiency and Distributed Generation Market Assessment	2004	New Jersey	Residential, Commercial & Industrial
Optimal Energy	Economically Achievable Energy Efficiency Potential in New England	2004	New England	Total
Demand Side Energy / Marbek	Manitoba Hydro DSM Market Potential Study	2003	Manitoba (Manitoba Hydro Territory)	Residential, Commercial & Industrial
ICF Consulting	Assessment of Energy Efficiency Potential In Georgia	2005	Georgia	Residential, Commercial & Industrial
ICF Consulting	Estimate of Energy Efficiency Potential for Wisconsin Public Service	2004	Wisconsin Public Service Co. territory	Residential, Commercial & Industrial

The results of the assessments are summarized in Table 3. These studies employ a variety of methods and definitions of different classes of potential are not always consistent. The lower ends of the ranges presented tend to emerge from studies employing more formal accounting models with endogenous energy efficiency measure adoption functions. Thus, adoption is forecast using a general adoption algorithm (as is used in the EEPM modeling analysis described in the next section), or as a function of program cost-effectiveness. The higher ends of the ranges are produced using methods that tend to reply on judgment-based estimates of adoption.

Table 3. Summary of Energy Efficiency Potential Studies

	Technical Potential	Economic Potential	Maximum Achievable Potential	Achievable Potential
Residential Sector	21%–36%	10.6%–30%	11%–35%	5.3%–21.7%
Commercial Sector	18%–41%	12.7%–35%	9%–39%	5.1%–17%
Industrial Sector	17%–38%	6.2%–32%	7%–60%	2%–19%

This variety of definition and approach shows most clearly in estimates of Maximum Achievable Potential. Some studies define this level of potential as that which represents the maximum amount of potential that could reasonably be captured through feasible policies. Other studies define this level in terms of the maximum market hare for efficiency measures, taking into account the fact that there will always be some fraction of the market that will not adopt a technology. This latter definition often results in an estimate of potential that closely matches the level of economic potential over time, and will always exceed by a substantial amount an estimate based on the former method.

For each of the studies identified, we calculated the savings percentage for the residential, commercial, and industrial sectors at five year intervals over the studies' time horizons. These savings percentages were then multiplied by projected baseline electricity sales for the respective years in order to arrive at the electricity usage that would result were the studies' assumptions and methods to be applied to Ontario. These savings estimates were then subtracted from the total baseline electricity to show predicted electricity sales under the extrapolated savings percentages.

Given the wide range of savings potential estimates, the studies have been classified into two subsets based upon the type of potential estimated.

- The first subset shows the potential electricity sales for Ontario based on the predicted savings percentages of studies identifying potential savings from minimally to moderately aggressive programs. There is significant variance between these studies in part because each study defines a minimally or moderately aggressive program differently. Also, in several cases these studies ignore potential efficiency savings in certain areas of the economy (i.e., residential lighting), or are limited to programs already in existence within the study area, reducing the overall savings identified.

- The second subset shows the potential electricity sales numbers for Ontario based on the **maximum achievable potential** from instituting a very aggressive CDM program requiring large sustained investment. These studies represent the upper bounds of potential energy efficiency savings.

Table 4 illustrates these ranges. The first column shows the reduction in sales, the second column shows the adjusted level of sales after accounting for the reductions and the third shows the relative reduction in sales.

Figure 7 and Figure 8 plot the levels of sales that would be observed in Ontario if the relative reductions predicted in the various studies were to be realized in the Province.

Table 4. Overview of Energy Efficiency Potential Studies and Program Experience

Historical Savings

		Total Savings Range (TW.hours)	Net Range (TW.hours)	% Savings Range
2010	Min	3.4	146.0	2.3%
	Max	4.9	144.5	3.3%
2015	Min	3.6	151.2	2.3%
	Max	11.2	143.5	7.3%
2020	Min	3.7	158.2	2.3%
	Max	18.8	143.1	11.6%
2025	Min	4.0	165.8	2.3%

Achievable with Moderately Aggressive CDM Programs

		Total Savings Range (TW.hours)	Net Range (TW.hours)	% Savings Range
2010	Min	3.0	146.4	2.0%
	Max	9.0	140.4	6.0%
2015	Min	6.3	148.5	4.0%
	Max	18.6	136.2	12.0%
2020	Min	9.4	152.5	5.8%
	Max	25.9	136.0	16.0%
2025	Min	12.5	157.3	7.3%
	Max	34.0	135.8	20.0%

Maximum Achievable Potential

		Total Savings Range (TW.hours)	Net Range (TW.hours)	% Savings Range
2010	Min	10.8	138.6	7.2%
	Max	23.6	125.7	15.8%
2015	Min	20.9	133.9	13.5%
	Max	48.2	106.5	31.2%
2020	Min	27.2	134.7	16.8%
	Max	62.2	99.7	38.4%
2025	Min	33.0	136.8	19.4%
	Max	75.5	94.3	44.5%

Figure 7. Predicted Sales from CDM50 Achievable Studies

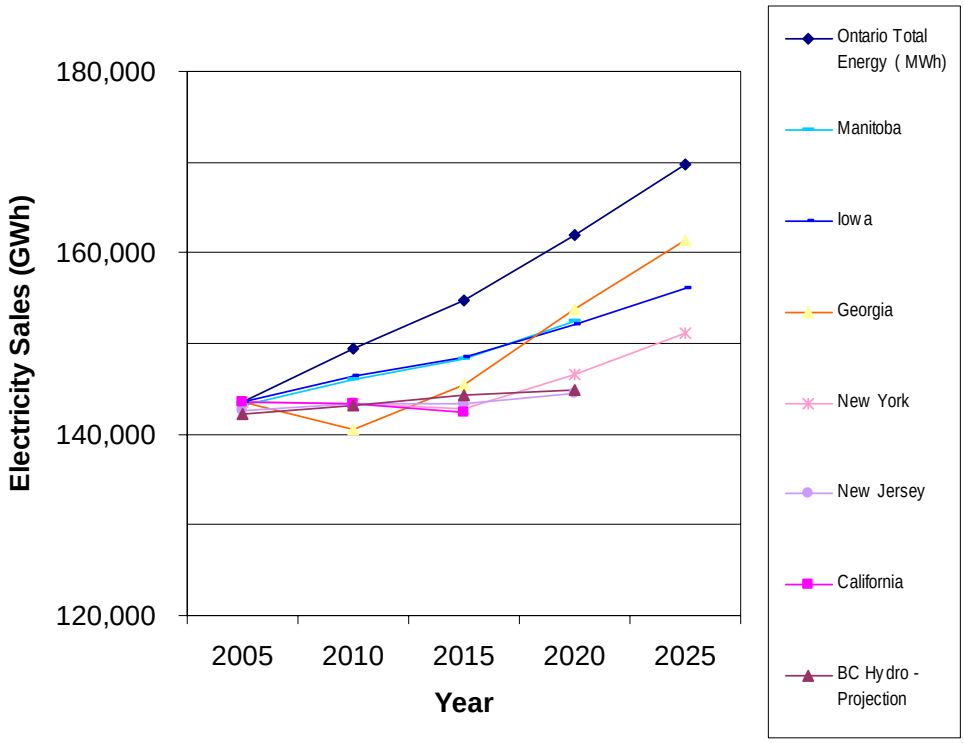
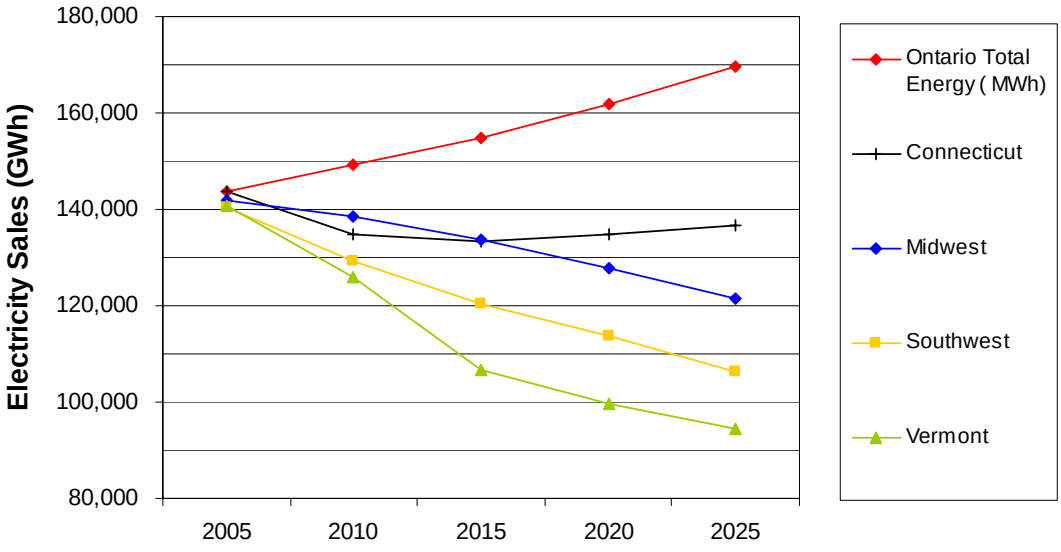


Figure 8. Predicted Sales from Economic Potential Studies



Estimates of CDM Program Impacts

We also reviewed the actual reported results of CDM programs in a number of North American jurisdictions with a view to applying the results of best practice programs to our calibration of the IESO/Navigant forecast as an indication of the impact that adoption of similar programs might have in Ontario.

We have compiled a partial list of such programs in Table 5. Unfortunately, although there is a growing literature on best practice and exemplary programs, the information readily available for these programs does not allow straightforward translation into potential impacts in Ontario. Program results tend to be expressed in absolute terms (GW.h or MW saved). The time allowed for this project did not allow us to collect base sales and demand data for each of the utilities for which we have program impact information. Moreover, much of the information pertaining to the achievements of best practice US energy efficiency programs is presented in relatively short time series and for specific programs as opposed to energy efficiency investment portfolios. In our experience it is a relatively more common accomplishment to achieve significant energy or demand savings from individual programs over several years than to maintain such success across a portfolio of programs and over a twenty year period. At least within the US and Canada we are not aware of a single jurisdiction that has maintained a consistent and significant investment over such an extended period. For example, even though the State of California has one of the longest and most accomplished energy efficiency track records on the continent, the actual investment and annual savings profile shows very pronounced oscillation, with annual spending ranging from $100 million to over $300 million.

Among the programs reviewed, some of the overall findings that have lead to greater penetration and increased savings were:

- Residential customers benefited from programs with point-of-purchase discounts and reduced administrative requirements. In addition, residential programs often featured prompt rebates, and hands-on customer service contact between customers and the utility or a contractor.

- Commercial customers benefited from programs with trained sales and implementation staff. Commercial programs were also more likely to have upstream involvement, with manufacturers, through the use of innovative marketing techniques.

- Other characteristics not limited to a specific sector included advanced market research and increased community-based marketing and advertising. Turnkey installation was also important in effective participation and implementation. Successful programs also featured close relationships among utilities, state agencies, and manufacturers. Also, in many of the programs, manufacturers were interested in increasing market share and promotional activity rather than financial incentives.

Table 5. Reviewed Energy Efficiency Program Data

Organization	Program	Year	Jurisdiction	Sector	Target Population	% Participation	Total Period GWh Savings	Total Period Costs / Budget (mil $)
Efficiency Vermont	Multi-family Residential Low-Income	1997–2002	Vermont	Residential	Unknown	Unknown	12.3	8.5
New Jersey Clean Energy Collaborative	Cool Advantage—Residential Air-conditioning	2002	New Jersey	Residential	50,000 (annual)	30%	14.0	17.0
NYSERDA	Keep Cool—Residential Air-conditioning	2002	New York	Residential	Unknown	Unknown	104.0	20.0
Proctor Engineering	Check Me!—Air conditioning	2002	California	Residential, Commercial	Entire US	Unknown	33.1	4.5
Northeast Residential Energy Star Appliances Initiative	Appliances	2002	New England, New York	Residential	2.2 mil	22% (2002) 2.4% (1998–2002)	0.8	0.2
SMUD	Refrigerator Pickup and Recycling	2002	Sacramento, CA	Residential	450,000	2%	13.7	1.2
Southern California Edison	Residential Appliance Recycling	2002	Southern California	Residential	3.9 mil	5-10%	44.6	4.8
Texas	Texas Energy Star Homes	2000–2002	Houston and Dallas, TX	Residential	78,000	15-20%	41.8	9.6
Austin, Texas	Green Buildings	2002	Austin, TX	Residential	1,200	57%	12.3	1.2
Northeast Energy Efficiency Partnership	Northeast Regional Energy Star Lighting	2001	Northeast	Residential	5.2 mil	Unknown	167.0	17.0
Northwest Energy Efficiency Alliance	Energy Star Residential Windows	1998–2001	Oregon, Washington, Montana, Idaho	Residential	New construction	75%	364.0	1.8
National Grid	Small Business Services	2002	New England	Commercial	77,000	33%	13.6	1.0

Organization	Program	Year	Jurisdiction	Sector	Target Population	% Participation	Total Period GWh Savings	Total Period Costs / Budget (mil $)
Avista Utilities	Rooftop HVAC Maintenance Service	2001	Spokane, WA	Commercial	18,000	11%	13.0	1.8
Portland General Electric	Existing Building Commissioning	2001	Portland, OR	Commercial	Unknown	Unknown	6.5	0.3
US EPA	Energy Star Monitor Power Management	2002	US	Commercial	Unknown	Unknown	232.0	0.5
Pacific Gas & Electric	Compressed Air Management Program	2003	San Francisco, CA	Commercial, Industrial	14,000	1%	9.4	0.2
Xcel Energy	Lighting	2001–2003	Minnesota	Commercial, Industrial	Unknown	Unknown	204.2	12.2
SMUD	Cool Roof	2001–2002	Sacramento, CA	Commercial	Unknown	Unknown	0.6	1.0
Pacific Gas & Electric	Upstream Residential Lighting	2001–2003	Northern California	Residential, Commercial	4.5 mil	8%	1521.5	34.9
SMUD	Shade Tree Program	2001–2003	Sacramento, CA	Residential	350,000	37%	14.4	4.8
Wisconsin Energy Conservation Commission	Energy Star Products	2001–2002	Wisconsin	Residential	2.3 mil	24%	25.5	18.8
Wisconsin Energy Conservation Commission	Energy Star Homes	2001–2002	Wisconsin	Residential	20,000	4%	0.4	0.3
Wisconsin Energy Conservation Commission	Home Performance	2001–2002	Wisconsin	Residential	1.4 mil	1%	5.1	3.8
Connecticut Light and Power, Western Massachusetts Electricity Company	Small Business Energy Advantage	2001–2003	Connecticut, Massachusetts	Commercial	108,000	35%	58.3	21.0

We have, as indicated, identified several sources of time series program impact data that can be matched to sales and demand data to yield percentage reductions in load resulting from long-term energy efficiency portfolio implementation.

- The US Department of Energy's Energy Information Administration (EIA) collected annual estimates of energy efficiency program impacts from the mid-1980s through 2002. These estimates when applied to historic sales and demand data for US utilities support an estimate of relative impact that can be compared with our estimates of achievable potential in Ontario.

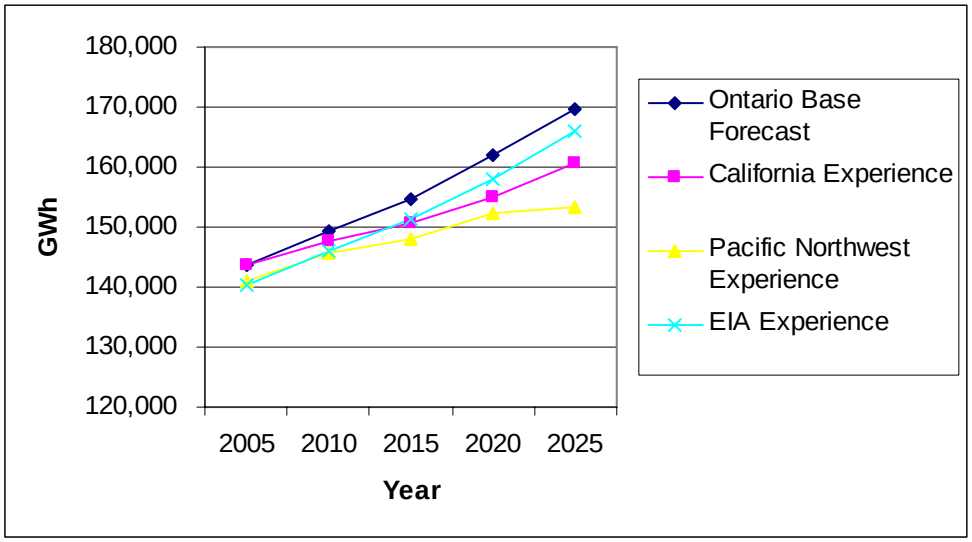
- The Regional Technical Forum associated with the Northwest Power Planning Council publishes annual energy efficiency program savings data dating to the 1980s as well as historical load data. The Pacific Northwest, by most accounts, has had some of the most consistently high levels of energy efficiency investment over the past two decades of any area aside from California. We have used these data to calculate annual percentage reductions in sales due to utility energy efficiency programs. Note that close to half of the total electricity reduction due to energy efficiency has been attributed to the effects of building codes and appliance standards. These impacts have been netted out of the data presented to enable a comparison of impacts of similar policy interventions.

- The California Energy Commission (CEC) has been tracking energy efficiency impacts upon total load from the mid-1970s through the present. More than half of the savings have been as a result of utility programs, with the remainder from building standards and appliance standards.

We have used these data to calculate annual percentage reductions in sales and demand, but again have subtracted the savings attributable to codes and standards. We then applied these relative savings to the IESO/Navigant forecast of electricity sales in Ontario as an indication of what the Ontario energy efficiency profile might look like if the Province were able to realize this same level of savings. However, it is important to not draw broad conclusions from this comparison. When examining such historical series, it often is not possible to determine the fraction of savings that are net of what would have occurred as the result of natural market forces. Generally, the theory and practice of program evaluation was not particularly sophisticated in the 1980s and early 1990s and it is likely that a substantial fraction of savings booked in early years of the California and Pacific Northwest experiences were attributed to information and education programs. Finally, as was noted earlier, energy efficiency savings are related to the underlying growth in economic and electricity demand. Generally speaking, savings opportunities are larger in faster growing systems. This is particularly true with respect to energy efficiency policies and investments targeting new construction.

With the above caveats in mind, we illustrate in Figure 9 the level of electricity sales in Ontario under scenarios based on these three sources of energy efficiency program experience.

Figure 9. Ontario Electricity Sales Scenarios Based on Program Experience



- The Regional Technical Forum (RTF) reports data on annual electricity savings due to utility- or public benefits-funded energy efficiency programs, state building codes and federal appliance standards for the period 1981 through 2004 for the states comprising the Northwest Power Planning Council. The RTF data show actual energy savings growing from about 1.7 percent in 1984 to over 15 percent by 2004. However, 38 percent of the cumulative savings are attributable, according to the RTF, to federal appliance efficiency standards and state building codes. Therefore, we first subtracted the savings attributable to building codes and appliance standards from the results so that we represent only the savings associated with direct financial investment in energy efficiency measures such as would occur under a traditional utility-funded energy efficiency program. These annual savings data were divided by historical annual retail sales for the same jurisdictions to yield percentage reductions in sales by year. These annual savings fractions were laid against our forecast of Ontario baseline sales to yield an estimate of the level of future sales in Ontario under circumstances that yield the same relative levels of savings.

- The EIA data show reported annual electricity savings by all US utilities for the period 1989 through 2003. However, the EIA data show the sometimes pronounced annual fluctuations produced by sudden increases or decreases in program funding. Over the period covered, annual percentage decreases in electricity sales typically varied between one and two percent. For purposes of this exercise, we selected the maximum annual reduction in sales for each customer class, applied those to our forecast of Ontario class sales and summed the result.

- Similar to the Pacific Northwest, California has a long history of investment in energy efficiency. Data reported by the California Energy Commission show that since 1976, total electricity sales have been reduced by 15 percent relative what they otherwise would have been. Although the pattern of annual savings again shows wide fluctuations based on funding cycles, the California trend has been toward steadily increasing cumulative savings. As is the case with the RTF data, the California savings data include the impacts of state building codes and appliance efficiency standards which together account for almost half of cumulative savings over the period. Again, these savings were subtracted from the total to enable a more reasonable comparison. For purposes of this exercise, we simply prepared a straight-line interpolation between an assumed savings level of 0 percent in 1976 to 7 percent in 2004. These annual numbers were then applied to the Ontario baseline forecast.

This exercise highlights several important points:

- First, the savings realized as the result of typical utility energy efficiency programs generally fall in line with estimates of what minimally to moderately aggressive CDM programs can achieve. This would include programs where up to 50% of the measure cost is covered by program incentives. However, this result is more an artifact of the difficulty in maintaining focus and funding over extended periods of time than it is a reflection of what actually might be achieved. All three time series examined show very pronounced annual variations in savings associated with similarly pronounced funding fluctuations. As will be discussed further below, actually converting the potential we estimate to be achievable into savings achieved will require a consistency in policy and investment that will be unprecedented.

- Second, although we have netted out the impacts of building codes and appliance standards in our presentation of data above, these policies are extremely important to capturing significant potential over the long run. Unlike conventional financial incentive and technical assistance programs that create transitory market effects, codes and standards lock in efficiency gains. Frequent updating of such standards to reflect improvements in practice and technology such as is done in California, ensures that the net savings associated with codes and standards continue to grow over time. Building codes and standards also tend to be lower cost policies to implement than are incentive programs that often entail significant marketing costs.

- The reported costs for the savings achieved in the Pacific Northwest are $2.6 billion ($2000 US). The real levelized cost for savings acquired has averaged approximately $0.013 (US) per kWh. The costs reported for the EIA savings data are slightly over $25 billion (US) for the period covered by the savings values, or approximately $0.04 (nominal US) per kWh. Energy efficiency program spending data for California are incomplete. However, we estimate conservatively that, since 1975, approximately $5 billion (US) have been spent, though the program composition has shifted markedly from

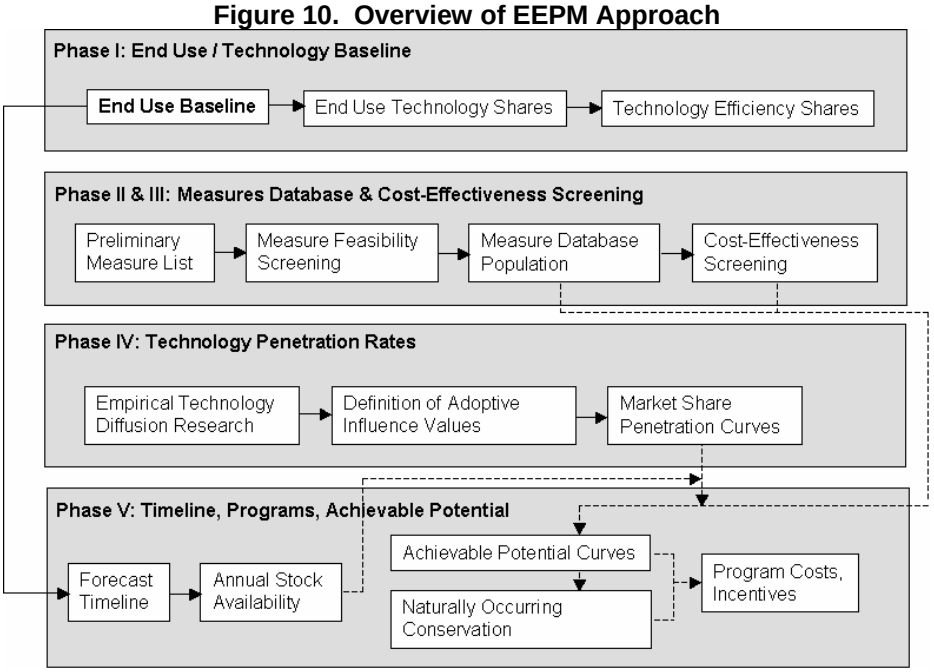
largely informational programs in the late 1970s to mostly rebate programs today. Since 1998, the average levelized cost of a conserved kWh has been slightly above $0.02 (US).

6. Achievable CDM – Accounting Based Assessment

Our third approach to estimating the size of the efficiency resource in Ontario, relative to the IESO/Navigant forecast, was to develop scenarios of the achievable CDM potential in Ontario over the 2006-2025 period under various assumptions about technology market shares and CDM program intensity. ICF Consulting develops and maintains a sophisticated measure-based Energy Efficiency Potential Model (EEPM) that projects the technical, economic, and achievable potential of a wide range of electric and natural gas efficiency upgrades under several market intervention scenarios. Based on a detailed segmentation of energy demand, a database of several hundred energy efficiency measures, and the current market saturations of these measures, EEPM assesses the extent to which program and policy interventions could increase the adoption of energy efficiency technologies. The final results of the modeling process include extensive data on which sectors, sub-sectors, end uses, and measures promise the greatest opportunities for energy efficiency improvement and the likely costs of acquiring that conservation. Like any model, the EEPM model requires considerable input data, and its outputs are sensitive to the initial calibration of the baseline forecast and the base year technology saturations and market shares. The state of readily available data on current technology saturations and market shares in Ontario is very poor, and these inputs had to be estimated by methods described in more detail below.

The five-stage EEPM modeling process is outlined in Figure 10.

Figure 10. Overview of EEPM Approach



Establish the Baseline Forecast

The IESO/Navigant forecast was used as the reference baseline for the EEPM modeling, combined with our sector, subsector and end use calibration of that baseline described in Section 2. We further segmented the baseline forecast to the following levels:

Technology Type. The technology type describes the class of technology used to deliver the end use energy service. The percentage splits among technology types are derived from available survey data or from best judgment. Note that for many end uses, only one technology type is applicable (i.e., residential refrigerators). We assume that any new load added to an end use is divided among the technology types in the same proportions for each year of the forecast. These proportions are the same regardless of policy intervention scenario. That is, EEPM does not model a scenario in which a program might encourage one technology type over another. All efficiency gains are achieved within the same technology type. As an example of how an end use might be further broken down into technology types, consider the segmentation of commercial interior lighting into the following technology types. Energy use for commercial sector lighting is divided among these technology types so that we can apply specific energy efficiency measures to the appropriate technology type.

- 4-foot fluorescent fixtures
- 8-foot fluorescent fixtures
- Incandescent or other medium screw-based lamp fixtures
- Exit signs
- High intensity discharge fixtures

Efficiency. For each technology type, the baseline forecast is further segmented into two or three efficiency levels. [11] Some technology types have three efficiency levels, while others only have two (Base and High Efficiency). To determine this initial segmentation, we utilize whatever energy efficiency program or installed saturation data are available and, when necessary, estimate saturations where these data are not available. These initial saturations are used to establish what proportion of load can be attributed to each efficiency level. As the model projects adoption of energy efficiency measures into the future, any new load or equipment being replaced at the end of its life is assigned to an efficiency level based on EEPM's projected market shares for high efficiency equipment in that year. The process of projecting future market shares for high efficiency measures will be discussed in greater detail below. The three efficiency levels are as follows:

- ***Existing***: The Existing efficiency level describes older equipment that is now below current codes or standard practice. Typically, any equipment bought today will be more efficient than equipment at the Existing level. For our commercial lighting example, T12 lamps with magnetic ballasts are the appropriate Existing efficiency level for 4-foot

[11] Appendix C specifies the intial market shares assumed and Appendix D contains the details of the technology type and efficiency segmentation employed in the analysis.

fluorescent fixtures. T12 fixtures are still used, but when replaced, very few are replaced with this older efficiency level.

- ***Base:*** The Base efficiency level describes current standard efficiency level equipment. Regular T8 lamps with electronic ballasts would represent the current standard practice.

- ***High Efficiency:*** The High Efficiency level represents a commercially available high efficiency alternative to the Base level equipment. Super T8 fixtures and ballasts would be the high efficiency alternative to regular T8 lamps and ballasts.

To clarify, the initial saturations among the efficiency levels define what proportion of total technology type electricity is used in each level in the base year. Over the forecast horizon, however, these saturations will change based on market shares that describe what proportion of new load and replaced equipment will be bought at each efficiency level. EEPM dynamically projects this stock turnover and determines how the marginal market shares of energy efficient equipment impact the saturation of the equipment over time.

Measure Database and Cost Effectiveness Screening

The measure database and cost effectiveness screening were described above in Section 4 under the discussion of Economic Potential. In summary, a database of about 300 energy efficiency measures is maintained in the EEPM model, and these were screened using the Technical Cost Test and the utility avoided cost to select for inclusion in the assessment of achievable potential, and using the Participant Cost Test and the present value of a future stream of estimated average retail prices to determine eligibility for inclusion in the estimate of "naturally occurring conservation", as defined in more detail below.

The Achievable Potential for Energy Efficiency

The achievable potential for electricity efficiency improvement is defined as the amount of cost-effective efficiency improvement expected to be captured as the result of specific policy or program actions, over-and-above the efficiency improvements attributable to normal consumer and market behavior and existing conservation policies and programs. This class of efficiency potential is distinguished from technical and economic potential in three important ways.

- First, as the term implies, achievable potential is defined in terms of what realistically can be captured by explicit actions.

- Second, and following from the first point, achievable potential is time-dependent. Achievable potential only can be realized by convincing consumers to replace existing equipment and practices with new, more efficient equipment and practices. It is often the case that consumers are most easily convinced to adopt high efficiency alternatives when they must make equipment replacement decisions anyway. Therefore, what is considered achievable potential grows over time as an increasing amount of the existing equipment stock reaches the end of its useful life.

- Finally, achievable potential intrinsically is a function of consumer behavior. The amount of potential one might expect is based on assumptions about what consumers will do when faced with various policy and program interventions. Because estimates of achievable potential consider this difficult-to-predict consumer behavior, they are inherently more uncertain than estimates of technical or economic potential.

To project achievable potential, EEPM estimates the adoption of cost-effective energy efficiency measures over time. The derivation of achievable potential involves several steps:

First, EEPM estimates what consumers will do in response to market forces, existing programs, and potential new programs. This requires some method to simulate or forecast the future market penetration of energy efficiency measures. The approach we employ recognizes that consumer choices are based on a wide variety of influences beyond the simple financial aspects of the purchase decision. These influences include consumer awareness of the product, the perceived advantages the product confers beyond energy savings (e.g., convenience, appearance), the perceived performance risk associated with the product, the status it might convey, and so on.[12] This approach is based on the observation that the best predictor of a product's future market share is its past and current market share.[13]

To implement this analysis, a straightforward mathematical function is employed to simulate the growth of energy efficiency measure market share over time for market-driven, existing program-driven and achievable energy efficiency improvements (See Equation 1). This function incorporates three key elements:

MS_0: Market share of the technology or product in an initial year
C: The product's assumed maximum market share; and
A: A parameter representing "adoptive influence," which influences the speed at which a technology gains share in the market.

Equation 1. Equation for Market Share in Year *t*

$$MS_t = \frac{C}{1 + e^{\left[-At + \ln\left(\frac{1 - MS_0 / C}{MS_0 / C}\right)\right]}}$$

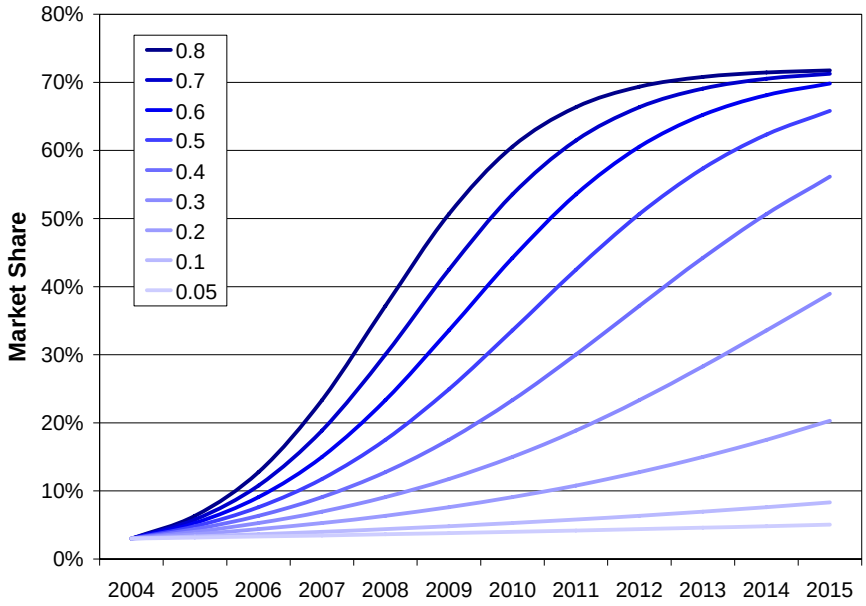
[12] For a complete discussion of the factors that affect consumer decision making and how these factors combine to affect market penetration, see, Everett M. Rogers. *Diffusion of Innovations*. New York: The Free Press. 1995.
[13] See, for example, Shipley, Anna M, et.al. "Market Diffusion Theory and the Penetration of Combined Heat and Power," *ACEEE Summer Study in Buildings*,. Washington, American Council for an Energy Efficient Economy. 2002, Blackman, A Wade. "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change* 6,41-63 (1974), Packey, Daniel J. *Market Penetration of New Energy Technologies*, National Renewable Energy Laboratory, NREL/TP-462-4860. 1993, and DeCanio, Stephen J., and Laitner, John A. "Modeling Technological Change in Energy Demand Forecasting," *Technological Forecasting and Social Change* 55, 249-263 (1997).

The adoptive influence parameter is estimated from available market share data. The magnitude of the parameter, which can vary between 0.0 and 1.0, determines the shape or compression of the S-shaped adoption curve, which in turn controls how fast a measure/technology/product diffuses through the market (See Figure 11).

Review of available market share data associated with energy efficiency programs shows that the adoptive influence can be significantly higher for measures affected by these programs than is the case for measures that are not being directly influenced by program intervention.

The marginal market share projected by this adoptive influence approach represents the annual fraction of replacement and new load that "chooses" energy efficiency as opposed to standard efficiency equipment and practices. The total saturation of energy efficiency measures grows through time as a direct function of the marginal share. Within the model, the adoptive influence parameter increases the marginal market share over time. The higher this value, the greater the annual increase in market share and the faster the increase in total saturation.

Figure 11. Projected Market Adoption under a Range of Adoptive Influence Values



EEPM also tracks the turnover of energy consuming equipment. For each year, a certain amount of energy consuming equipment must be replaced and new equipment is added. As existing equipment reaches the end of its useful life and is replaced, new equipment is purchased at either a base or high-efficiency level as determined by the projected market shares for high-efficiency equipment.

Replace-on-fail measures are only available for implementation as older equipment is replaced, but retrofit measures may be implemented at any time. Retrofit measures include:

- Measures that do not replace any existing equipment (e.g., pipe insulation added to non-insulated pipes).

- Measures that replace existing equipment but are cost-effective even when the full cost of the new high-efficiency equipment is considered. For example, the incremental cost of a high-efficiency 15 SEER residential central air conditioning unit is the difference in cost between a 15 SEER unit and a standard 13 SEER unit. For an equipment replacement such as this, cost-effectiveness for replace-on-fail is calculated based on this incremental cost and the incremental savings achieved by selecting a 15 SEER over a 13 SEER unit. However, if the incremental savings achieved by the 15 SEER unit were enough to overcome the *full* cost of the equipment and installation, the existing unit may be replaced by the 15 SEER at any time.

Based on our research of historical energy efficiency program influence on market shares, we have calibrated EEPM's market adoption curves to several scenarios:

Naturally Occurring -- This scenario reflects efficiency gains from turnover of older equipment to current standard equipment and the adoption of high-efficiency equipment due to natural market forces and existing energy efficiency programs. Even in the absence of additional program or policy interventions, consumers will take actions that improve the efficiency of their energy-consuming equipment. These energy savings make up what we call naturally occurring conservation. Naturally occurring conservation is the result of three general classes of structural market changes and consumer decisions:

- **Equipment Retirement**—Some proportion of currently installed equipment is older and less efficient than current standard equipment. As this stock of equipment reaches the end of its useful life, it will be replaced with current standard efficiency equipment. We term the savings achieved from this turnover as "equipment retirement."

- **Market Driven Conservation** -- Some consumers will independently choose the high efficiency technology based on the prices they face for the equipment in the market and their perceptions of the costs and benefits of choosing the efficient option. The energy efficiency gain that results from these choices is sometimes called "market-driven."

- **Existing Program-Driven Conservation**—Other consumers will tend to choose standard efficiency options unless offered some incentive to buy more efficient equipment. Consumers who make energy efficiency investments by taking advantage of incentive programs already offered contribute to what is referred to as "existing program-driven conservation."

Because we are most interested in the extent to which policies and programs can achieve savings above and beyond natural conservation, it is important to understand the concepts underlying naturally occurring conservation. There are two points to keep in mind:

- First, because naturally occurring conservation will occur even in the absence of new policy or program interventions, it is embedded within the baseline forecast. That is, without naturally occurring conservation, the baseline forecast would be higher.

- Second, given a long time horizon, naturally occurring conservation will catch up to any of the modeled policy scenarios. Even under the naturally occurring scenario, market shares of high-efficiency technologies will rise slowly over time. Eventually, these market shares reach their upper limit and cannot grow further. As a result, the various policy scenarios will tend to converge with the baseline forecast over the long-term as the naturally occurring scenario slowly captures the same savings achieved by the policy scenarios. The root cause of this phenomenon is that we only record savings for energy efficiency measures that we know to be commercially available now or in the near future. Given enough time, these energy efficiency opportunities will often be extensively adopted regardless of additional program interventions. To partially address this effect, we have incorporated a second generation of energy efficiency measures into the EEPM structure as emerging technologies.

Treatment of Emerging Technologies

As the market for a particular energy efficiency technology matures, it may be reasonable to make that technology the new standard. This is particularly relevant for a study with a 20-year horizon such as this one.

To model the changing technological landscape, we have included emerging or advanced energy efficiency technologies in our analysis for the OPA. Emerging technologies have been incorporated as follows:

- As for any other energy efficiency measure, cost and savings information for each emerging technology have been recorded in EEPM's energy efficiency measure database.

- Once the market share of an energy efficiency measure approaches its market share cap, EEPM sets this energy efficiency measure as the new standard efficiency option. The emerging efficiency technology is then introduced with an initial market share of about 10%. This emerging technology then is able to grow its market share over time as the new high efficiency option.

- It is also possible to set a particular year in which a new standard is to take effect. In that year, the energy efficiency measure is set as the standard efficiency option and the emerging technology enters the market as the new high efficiency option.

This process, in essence, models the transformation of the market to high-efficiency equipment and the subsequent entrance into the market of the next generation of high-efficiency equipment. This delays substantially the convergence of the policy scenarios with the naturally occurring scenario. Essentially, it expands the opportunities available to programs for improving energy efficiency.

We should note that the technical applicability and economics of these emerging technologies is more speculative than for current commercially available technologies, but it is important to address broad technological change over a 20-year time frame.

Key Data Inputs

There are three basic types of data required for the Energy Efficiency Potential Model approach.[14]

Load Data -- These data include any available electricity sales or peak demand forecasts as well as segmentations of load by sectors, sub-sector, end use, and technology type. The electricity sales forecast was developed as described above from historical energy consumption trends and the IESO's projected energy demand drivers. As the potential for electricity efficiency will vary depending on the distribution of the forecast demand between sectors and end uses, the CDM potential developed here is unique not only to the IESO/Navigant forecast, but also to our particular sector and end use calibration of that forecast. In that calibration, described above in Section 2, the growth in electricity demand is unevenly distributed across sectors. In the residential sector, there is a continuation of the electricity efficiency improvement trend established over the 1990-2003 period. In the commercial sector there is strong growth in activity but the basic forecast calibration reflects a continuation of electricity intensities (electricity per unit of floor area) at their current level. In the industrial sector, the forecast calibration assumes the electricity intensive industries maintain their 62% share of industrial electricity use, with relatively little improvement therefore in the overall electricity productivity of Ontario industrial production.

Utility Cost Data -- Avoided utility costs of electricity are used to determine the resource value of conserved energy and determine cost-effectiveness of energy efficiency measures and program portfolios. Our source for these data was the recent Navigant Consulting study on avoided costs presented to Hydro One Networks.[15]

Energy Efficiency Market Data – The EEPM model requires inputs that specify the market shares that energy efficient technologies currently hold in Ontario. Unfortunately, information on technology market shares is not readily available across sectors and end uses for Ontario. In

[14] For a study with a longer timeframe, we would also include some refinement of our energy efficiency measure database. However, the database has been recently updated, and we have also completed building simulations for weather-sensitive measures that reflect the climate of the northern US—a reasonable approximation of energy efficiency measure performance in Ontario.

[15] Navigant Consulting, *Avoided Cost Analysis for the Evaluation of CDM Measures*. June 2005.

most markets there is very limited information available on either the percentage of the market now using efficient technologies (saturations) or the percentage of replacement decisions that select high efficiency options (market shares). Ontario is not unique in facing this problem. As a result, it was necessary to make some assumptions with respect to the current market shares of efficient technologies.

The CDM potential results described below are based on assumed initial market shares that were tied directly to the IESO/Navigant forecast. This was done by first generating a frozen efficiency version of our calibration of the IESO/Navigant forecast, and taking this as a reasonable approximation of static efficiency projection of electricity demand in Ontario. The EEPM model was then used to determine the initial market shares implied by the difference between the static efficiency projection and the IESO/Navigant forecast. For some end uses, the initial market shares calculated by this procedure are low compared to anecdotal information on the current uptake of these technologies in Ontario (e.g. commercial lighting), but they are nevertheless the market shares required for consistency with the calibration of the IESO/Navigant forecast. For example, what information does exist on sector and end-use breakdown of electricity use in Ontario in recent years (i.e. the OEE database used in our calibration of the forecast) suggests that there has been very little improvement in the efficiency of commercial lighting in Ontario buildings, and so the implied market share results for commercial lighting come out very low in this exercise. To the extent the assumed initial market shares are lower than what is actually taking place in the field (which we do not know), then the potential for CDM programs and incentives to increase the market share will tend to be overestimated. On the other hand, for our CDM estimate to be consistent with the IESO/Navigant forecast, if a higher market shares for efficient technologies were to be assumed (e.g. in commercial lighting), it would require a compensating, downward adjustment somewhere else in our calibration of the IESO/Navigant forecast. This issue illustrates clearly the difficulty of assessing the CDM resource against a single line forecast and without reliable information on current saturations and market shares. We address this issue in more detail below in the discussion of the sensitivity analysis of CDM estimate presented here.

CDM Scenario Results

The tables and figures on the following pages summarize our EEPM-based accounting model results for achievable energy efficiency potential from 2005 to 2025. Fully detailed tables and graphs of our results have been provided to the OPA. The following scenarios were generated:

- ***Naturally-Ocurring/Static Efficiency:*** Naturally occurring conservation reflects efficiency gains from turnover of older equipment to current standard equipment and the adoption of high-efficiency equipment due to natural market forces and existing energy efficiency programs. The scenario is calibrated to adoptive influence values (parameter $A \approx 0.125$ in the equation on page 27) reflecting the adoption behavior characteristic of an environment in which there is a relatively high level of awareness of energy efficiency and some history of program activity, but no current subsidized energy efficiency activity beyond existing codes and standards. The Base Forecast (i.e. the IESO/Navigant

forecast) includes this level of naturally occurring conservation, so we have added naturally occurring conservation on top of the Base Forecast in order to represent load growth in a state of Static Efficiency where no efficiency gains are realized.

- ***Base Forecast:*** This is the segmented end use calibration of the IESO/Navigant forecast, as described in Section 2 above.

- ***CDM25:*** This scenario attempts to mimic program intervention that is largely information-based, with financial incentives for measure installation set to 25% of measure incremental cost. (adoptive influence parameter $A \approx 0.25$)

- ***CDM50:*** This scenario reflects a fairly common program approach wherein financial incentives are set equal to approximately 50% of measure incremental cost. In addition, program implementation costs are assumed to be higher due to more intensive marketing and technical assistance efforts. ($A \approx 0.50$)

- ***CDM100:*** Here we assume that incentives are equal to 100% of measure incremental costs and program implementation costs are correspondingly higher reflecting intensive recruiting and technical assistance. ($A \approx 0.75$) This type of scenario is considered to reflect the maximum possible achievable potential; however, even with financial incentives covering the full cost of efficient equipment, some customers will not be influenced to invest in energy efficiency.

- ***CDM100 plus Aggressive Standards:*** For this scenario, we have built additional structure into the accounting framework to allow us to simulate the introduction of emerging technologies. This structure can be used to represent imposition of a broad range of generic standards. For example, switching the year at which the advanced technologies begin to enter the market we convert the current high efficient measures to standards. For this scenario, we assume that Ontario implements a series of aggressive standards starting in 2008 to build upon the rapid market share growth achieved under the CDM100 scenario. Once these standards are implemented, the minimum efficiency equipment that can be bought is the high-efficiency category. At the same time, an emerging technology enters the market at a low initial market share and is gradually accelerated into the market.

As indicated in the tables and figures below, estimated achievable energy efficiency potential is greatest in the commercial sector, with the balance divided fairly evenly between the residential and industrial sectors. Lighting, space heating, and industrial processes make up the majority of electricity sales savings potential. Commercial office equipment and air conditioning also contribute significantly to overall savings. Peak demand savings potential is dominated by air conditioning and industrial processes, with lighting also playing an important role.[16]

[16] Appendix E contains the details of the EEPM modeling runs.

The CDM resource can be deployed on a relatively short time frame; in fact, in percentage terms it can make a bigger difference in the short term than in the longer term, given the capabilities and costs of the technologies currently available. CDM programs are particularly effective at accelerating the uptake of electricity efficiency technologies that would probably, eventually, be adopted. This aspect of the CDM resource is especially relevant to the prospect of short to medium term supply/demand tensions in the Ontario system.

It bears repeating that these results are only relevant to the IESO/Navigant forecast, and in particular to our sector and end use calibration of that forecast. Except for the residential sector, we found that calibration to the IESO/Navigant forecast required assuming a continuation of the very modest electricity efficiency improvements that have evidently characterized Ontario electricity use in the last fifteen years. This in turn resulted in the implication that market shares of electricity efficient technologies are relatively low in Ontario, and that CDM programmes could therefore be quite effective at accelerating their uptake. The potential for CDM will be less if the existing technology market shares are higher than assumed here, but for this to be true the calibration of the base forecast would have to be adjusted in some other area (to keep the total demand from falling below the forecast level) and/or the base forecast itself would have to be adjusted downward.

Table 6. Load Forecast Under Achievable Potential Scenarios (Electricity Sales, TW.hours)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	145.3	154.8	166.6	181.1	198.1
Base Forecast	143.6	149.4	155.8	163.0	171.0
CDM25	143.6	148.2	150.1	150.3	153.8
CDM50	143.6	144.4	135.4	135.8	143.3
CDM100	143.6	138.5	127.5	132.6	142.8
CDM100 Plus Standards	143.6	122.2	123.7	132.2	142.5

Table 7. Load Forecast Under Achievable Potential Scenarios (Peak Demand, GW)

Forecast	2005	2010	2015	2020	2025
Static Efficiency	23.6	26.1	28.9	32.1	35.4
Base Forecast	23.3	24.8	26.4	28.2	30.0
CDM25	23.3	24.6	25.5	26.3	27.7
CDM50	23.3	24.0	23.4	24.1	25.7
CDM100	23.3	23.0	22.1	23.4	25.6
CDM100 Plus Standards	23.3	20.2	21.0	23.1	25.3

Figure 12. Achievable Potential Scenarios – 2005-2025 (Electricity Sales)

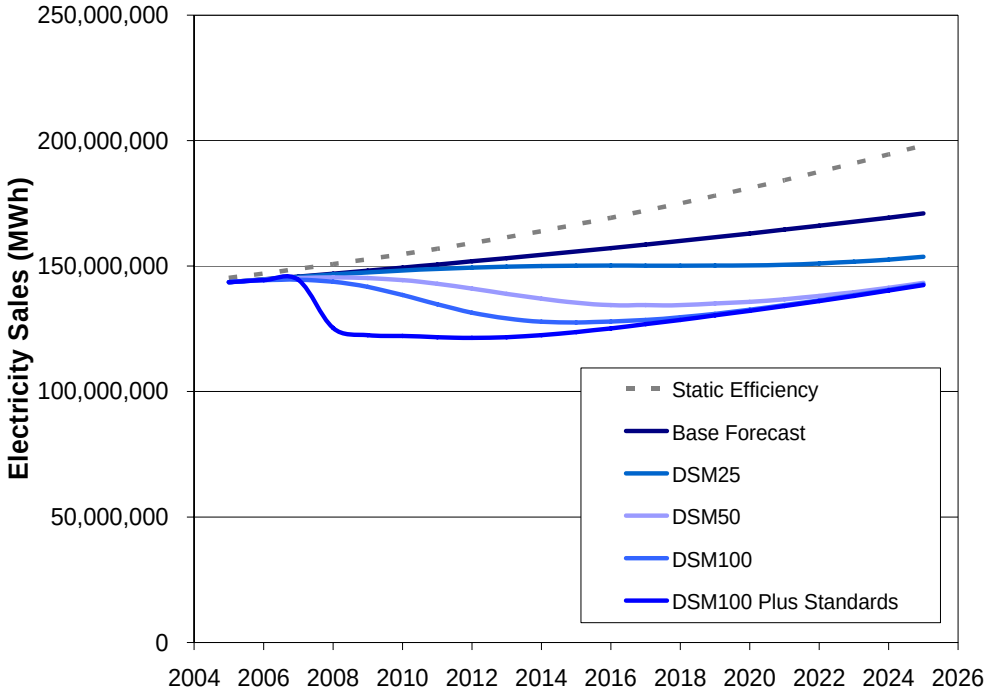


Figure 13. Achievable Potential Scenarios – 2005-2025 (Peak Demand)

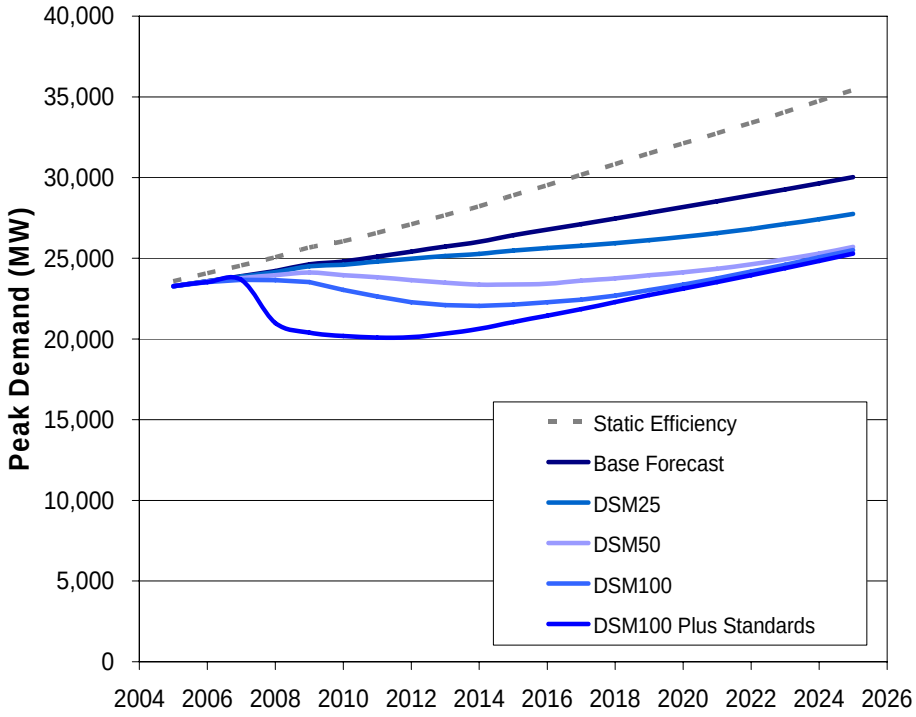


Figure 14. 2015 Achievable Potential by Sector (Electricity Sales)

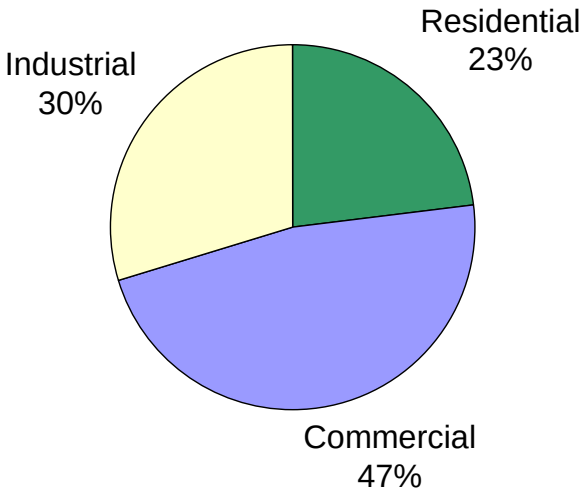


Figure 15. 2015 Achievable Potential by Sector (Peak Demand)

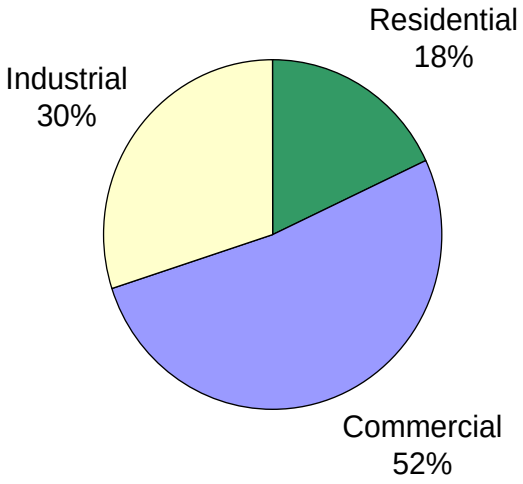


Figure 16. 2015 Achievable Potential by End Use (Electricity Sales)

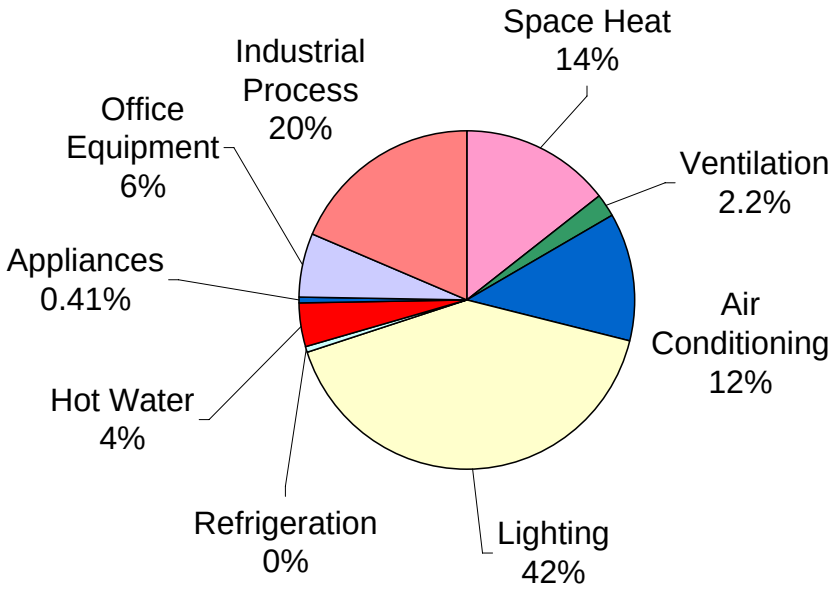


Figure 17. 2015 Achievable Potential by End Use (Peak Demand)

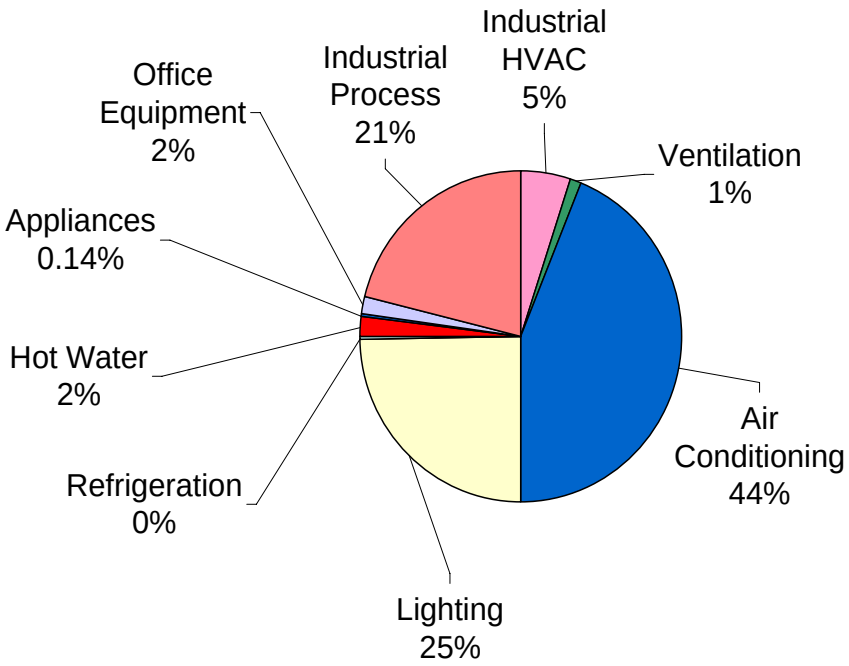


Figure 18. 2015 Achievable Potential by Sector and End Use (Electricity Sales)

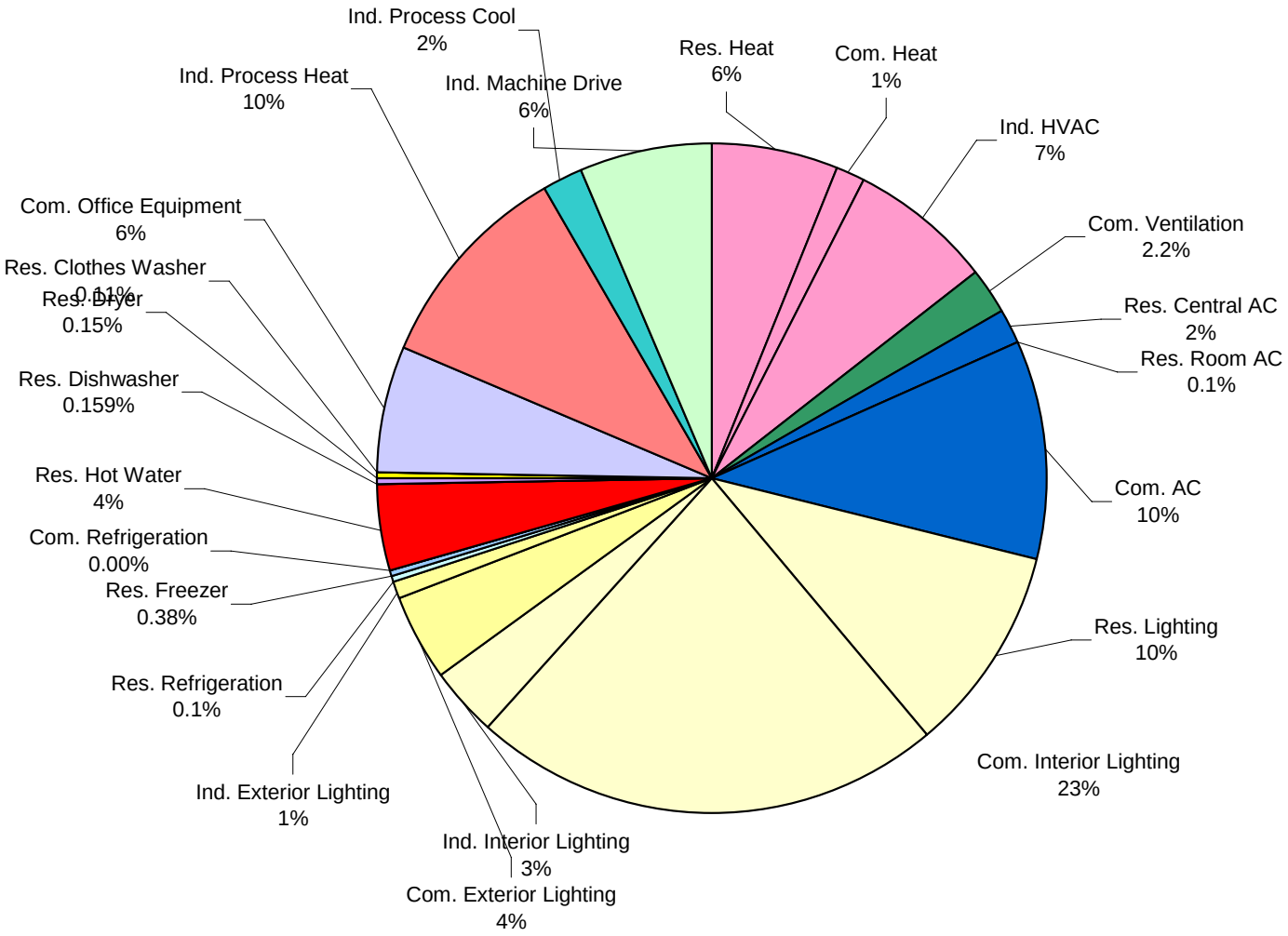
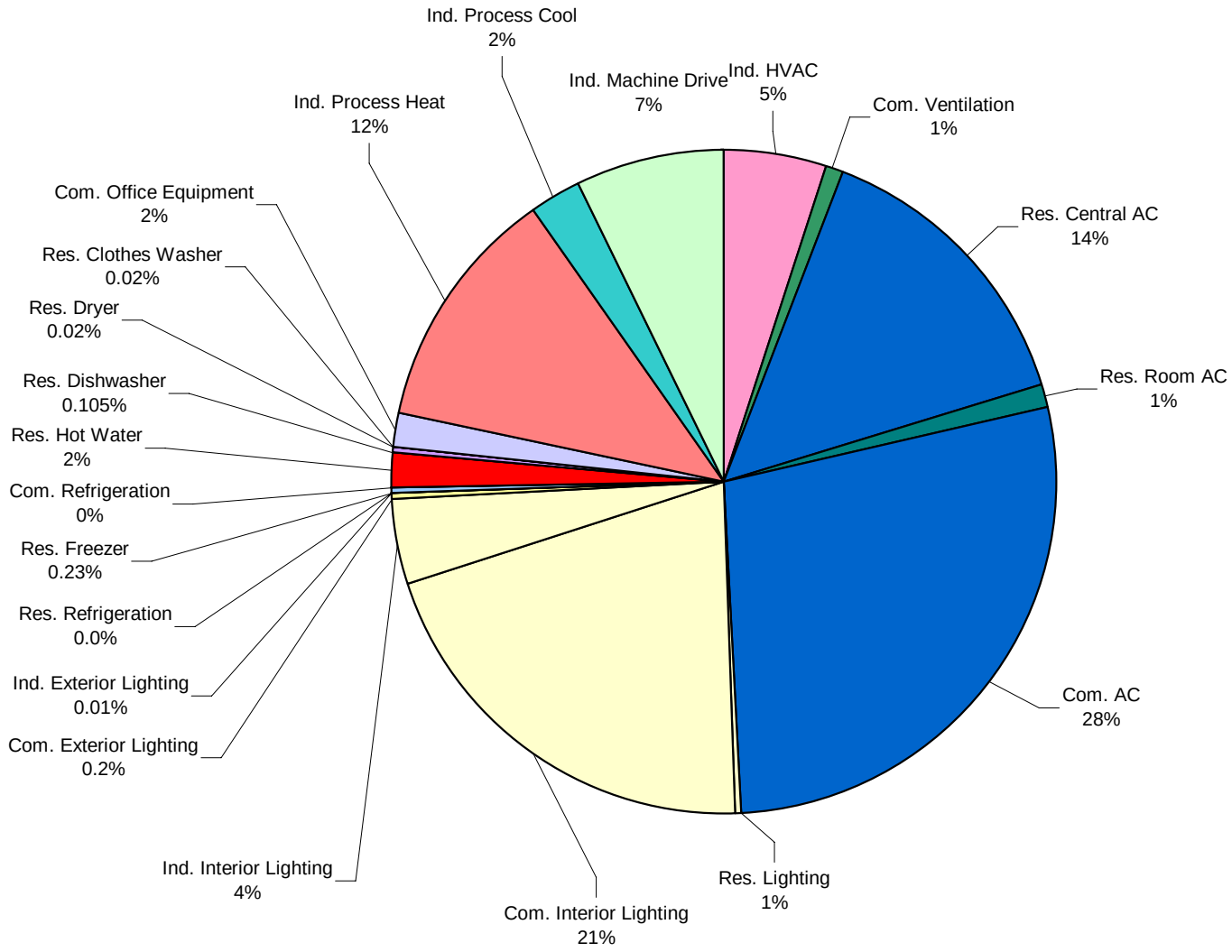


Figure 19. 2015 Achievable Potential by Sector and End Use (Peak Demand)


Ind. Process Cool
2%
Ind. Machine Drive
7%
Ind. HVAC
5%
Com. Ventilation
1%
Ind. Process Heat
12%
Com. Office Equipment
2%
Res. Central AC
14%
Res. Clothes Washer
0.02%
Res. Dryer
0.02%
Res. Room AC
1%
Res. Dishwasher
0.105%
Res. Hot Water
2%
Com. Refrigeration
0%
Res. Freezer
0.23%
Res. Refrigeration
0.0%
Com. AC
28%
Ind. Exterior Lighting
0.01%
Com. Exterior Lighting
0.2%
Ind. Interior Lighting
4%
Com. Interior Lighting
21%
Res. Lighting
1%

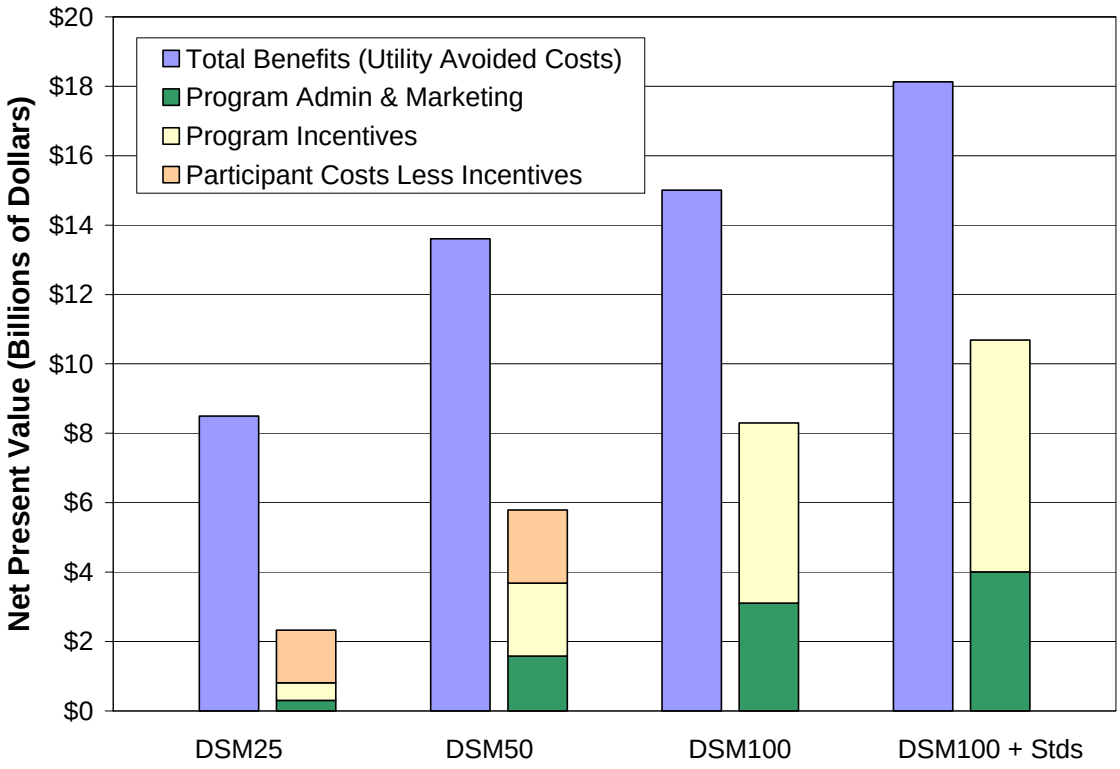
Program Costs

The program cost calculations summarized here[17] are based on technology-specific measures. For all scenarios it was assumed that program administration costs equal 60% of incentive costs. All costs and benefits were converted to present value using a discount rate of 8%. Program costs and benefits were analyzed from both the participants' and utilities' viewpoints. The Total Resource Cost (TRC) test shows the present value of benefits ranging from $8 to $18 billion, while costs range from $2 billion to over $10 billion. In all cases, program benefits greatly exceed costs. In the DSM25 scenario, the benefit cost ratio – the extent to which benefits exceed cost - is roughly 3.65. In the DSM100 scenario, the BCR is much smaller but benefits are still 1.7 times the program costs.

Under the Participant Cost Test, the net benefit to participants range from $5.7 to $21.3 billion The benefit cost ratio ranges from 3.8 under DSM25 to 4.3 under the DSM100 scenario.

Under both scenarios the benefit cost ratio is highest for the commercial sector and lowest for the industrial sector, however, in all cases the benefits exceed both participant and total resource costs.

Figure 20. Program Costs and Benefits for CDM Scenarios



[17] Details of the program cost calculations are included in Appendix F.

Sensitivity Analysis

Initial Market Shares

The CDM assessment is very sensitive to initial technology market shares – the market shares that electricity efficient technologies hold today, before the application of CDM programs. Table 8 compares two sets of initial market shares – the first based on ICF observations of recent U.S. market activity, and the second consisting of the market shares that are consistent with the calibration of the IESO/Navigant forecast and used in the CDM assessment for Ontario presented above.

Table 8. Initial Market Shares: Comparison of Alternatives

End Use or Measure	Percentage of Purchasers Currently Assumed to Choose High Efficiency Option	
	Estimates based on Some U.S. Experience	Final Inputs (Resulting from Forecast Calibration)
Residential Lighting (Compact Fluorescent Lights)	6.7	0.4
Residential Refrigerators	44.1	28.9
Residential Water Heater (i.e. tank/pipe insulation)	10	2.2
Residential Air Conditioning	7.0	1.7
Commercial Lighting (T8's with electronic ballasts)	20	1.3
Commercial – Exit Signs (LED Exit signs)	66	0.5
Commercial Cooling (high efficiency packaged units)	20	4.3
Ventilation systems (Variable Frequency Drives for Motor)	35	6.7
Office Equipment – power management enabled	10	1.4

The impact on the CDM assessment of using the higher set of market shares is illustrated by a comparison of Figure 21 and Figure 22 on the following page. Figure 21 is a copy of Figure 12 and Figure 22 shows the effect on the CDM assessment of replacing the market shares in the right-hand column of Table 8 with the values in the left-hand column.[18] The life expectancy of each technology and hence the rate at which stock is turned over remains unchanged, as do the level of energy use associated with the standard and efficient technology choices. With the higher values of the initial market shares (Figure 1Figure 22), the potential for CDM to effectively increase market shares is that much smaller, and hence the lower assessment of the overall CDM potential.

[18] There are some other input assumption differences between the two sets of results illustrated in the figures, but the differences in market share account for almost the entire difference in the resulting CDM assessments.

Figure 21. CDM Assessment with Initial Market Shares Calibrated to IESO/Navigant Forecast

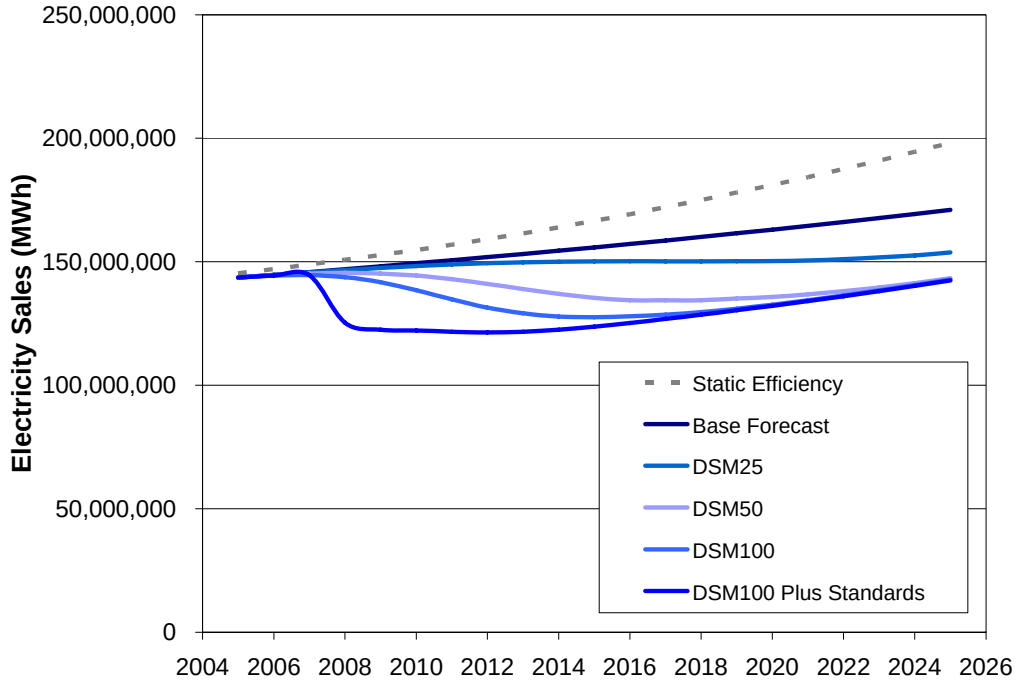
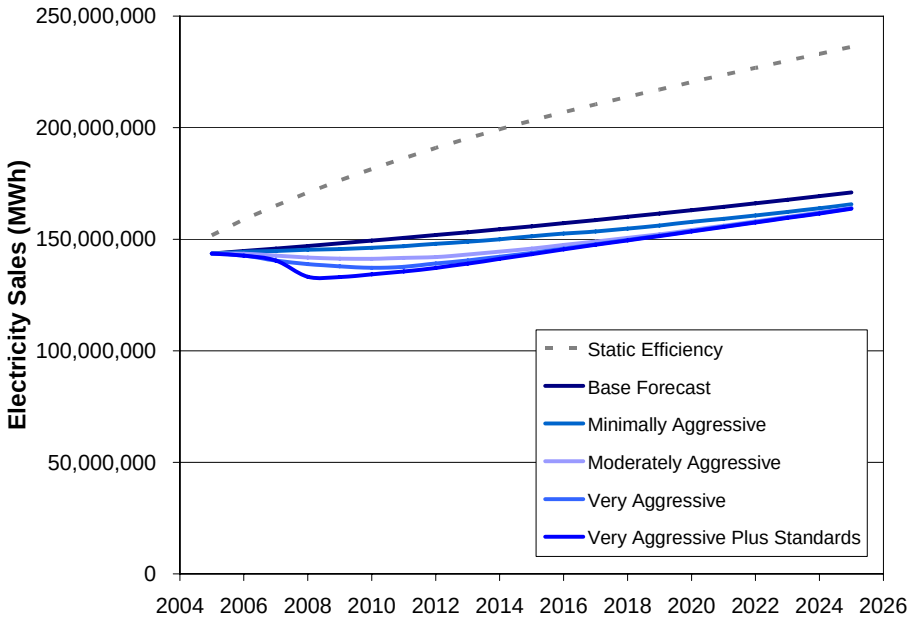


Figure 22. CDM Assessment with Initial Market Shares Based on U.S. Experience[19]



The CDM100 scenario in Figure 21 shows a 20% reduction from the Base Forecast, compared to a 4.5% reduction in Figure 22. Lower initial market shares also mean that CDM programs can

[19] Note that the terms "minimally aggressive", "moderately aggressive" and "very aggressive" are interchangeable with the terms DSM25, DSM50 and DSM100, respectively.

result in the changeover to higher efficiency technology much sooner than would otherwise have been the case and so the assessment portrayed in Figure 21 not only shows a greater CDM potential, but also a greater relative impact in the near term. Another side effect of the lower initial market shares (Figure 21) is that the degree of convergence between the scenarios is reduced. With the lower initial market shares, the point of convergence between the scenarios is beyond the study period.

These two different projections effectively represent two points on a spectrum of possible potentials. Refining this estimate will require additional work and experience to determine actual levels of energy efficiency market shares in Ontario. Perhaps more important, the divergent results illustrate the difficulty of assessing the CDM potential against a single line and highly aggregated forecast such as represented by the IESO/Navigant forecast. While it may be that the initial market shares in the left-hand column of Table 8 and reflected in the results in Figure 22 are closer to actual market activity, it is the market shares in the right-hand column that are consistent with the end use calibrated version of the IESO/Navigant forecast. The resolution of this dilemma requires not only better information on the actual technology saturations and market shares characteristic of the Ontario electricity market today, but also an integrated analysis of the level and end use pattern of electricity demand in Ontario, both now and under different scenarios of demographic and economic development.

Additional Sensitivity Analysis

We also carried out a number of sensitivity analyses on the CDM assessment results.[20] Selected variables were varied through a range of +/-30% around their assumed values while holding all other variables constant. This analysis was carried out for both individual and selected combinations of variables to determine the impact of changing model assumptions, including market shares, but also saturations and levels of market barriers. Details of these sensitivity model runs have been provided to the OPA; some key findings are provided below:

- The resulting uncertainty is much larger for the residential sector than for any of the other sectors. The main reason for this is that residential CDM potential depends on a relatively small group of measures. For instance, the majority of MWh savings potential in the residential sector comes from the use of Compact Fluorescent Lamps (CFL) replacing incandescent lights. If the values used for CFL savings factors, applicability factors, initial market share, market barrier level, or other variables differ from the levels assumed, then the impact on resulting CDM potential could be significant.

- Peak demands in the residential sector are almost entirely driven by air conditioning. Again, if values for the variables relating to air conditioning were to change then the impact on peak demand would be significant.
- In contrast, in the commercial and industrial sectors, there are many more end uses and technology types making up the CDM potential. Therefore, changes to any one variable or handful of variables do not significantly influence the results.

[20] Appendix G contains additional outputs from the sensitivity analysis.

- With few exceptions, neither the discount rate nor avoided electricity costs are major sensitivities. Small marginal changes to the discount rate or avoided costs do not substantially increase or decrease the number of technologies that are cost-effective.

- Overall, the sensitivity analysis showed that there is a very high degree of sensitivity to assumptions about market shares and market share growth. Unfortunately, as already discussed above, this is an area where limited data is currently available.

- Unlike market shares, some of the variables have a clear linear input on the results. These would include kWh and kW savings factors or applicability factors. Any change in these numbers will simply scale savings from that measure up or down.

With the exception of the industrial sector, our best estimates of CDM potential (the single line estimates shown inside the uncertainty bands in the following figures) are on the high end of what the sensitivity analysis shows is likely. For example, in cases where our estimate of potential is above the 75th percentile, there is a 75% probability that the potential would actually fall below our estimate. This is particularly true for the residential sector, where a change to the market barrier level for CFLs or central AC measures could reduce the projected potential by almost one third or one half. In other words, if customers are significantly less responsive to programs than indicated in the model the estimated potential would not be realized.

The following graphs show the impact of changing selected variables by +/-30% relative to the original values used in the EEPM model.

Figure 23. Residential Potential for Energy Reductions – Key Sensitivities

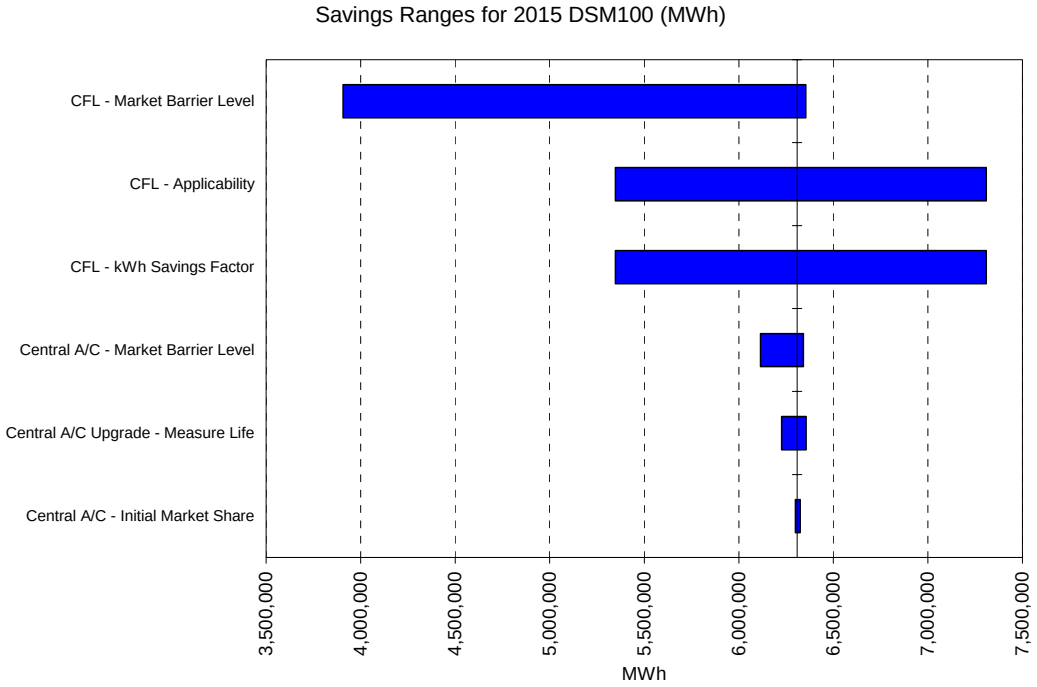


Figure 24. Residential Potential for Demand Reduction – Key Sensitivities

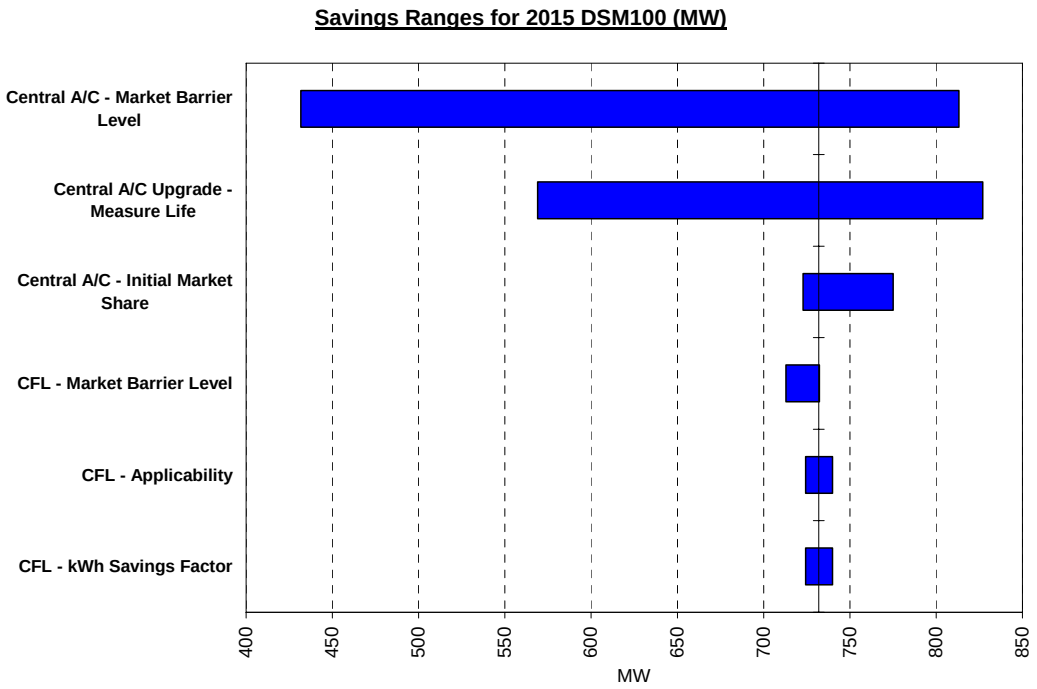


Figure 25. Commercial Sector Potential for Energy Reductions – Key Sensitivities

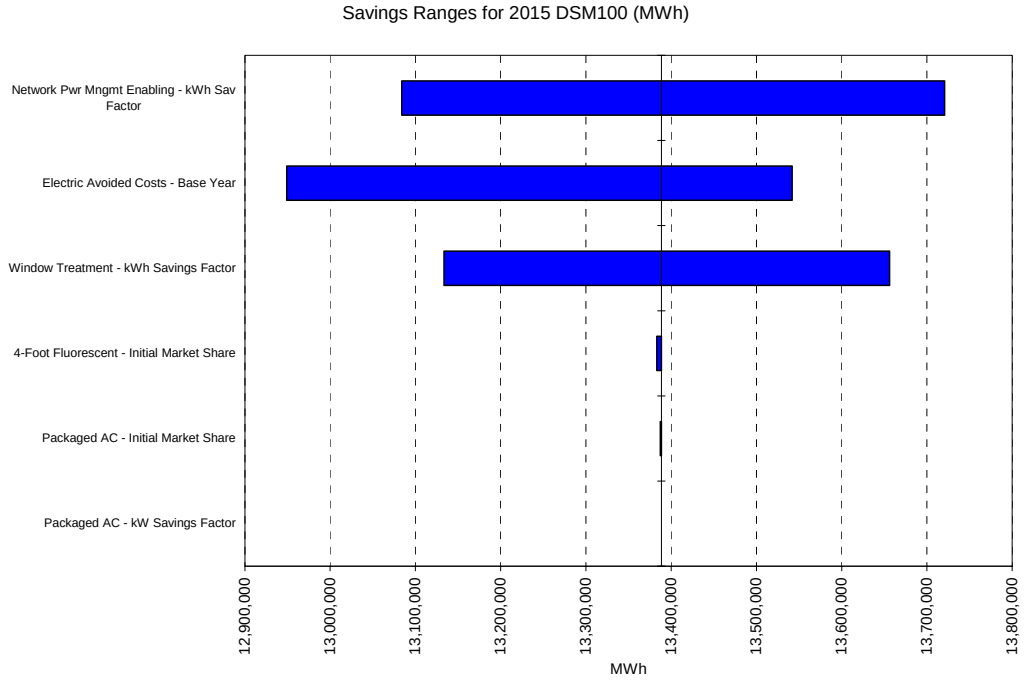
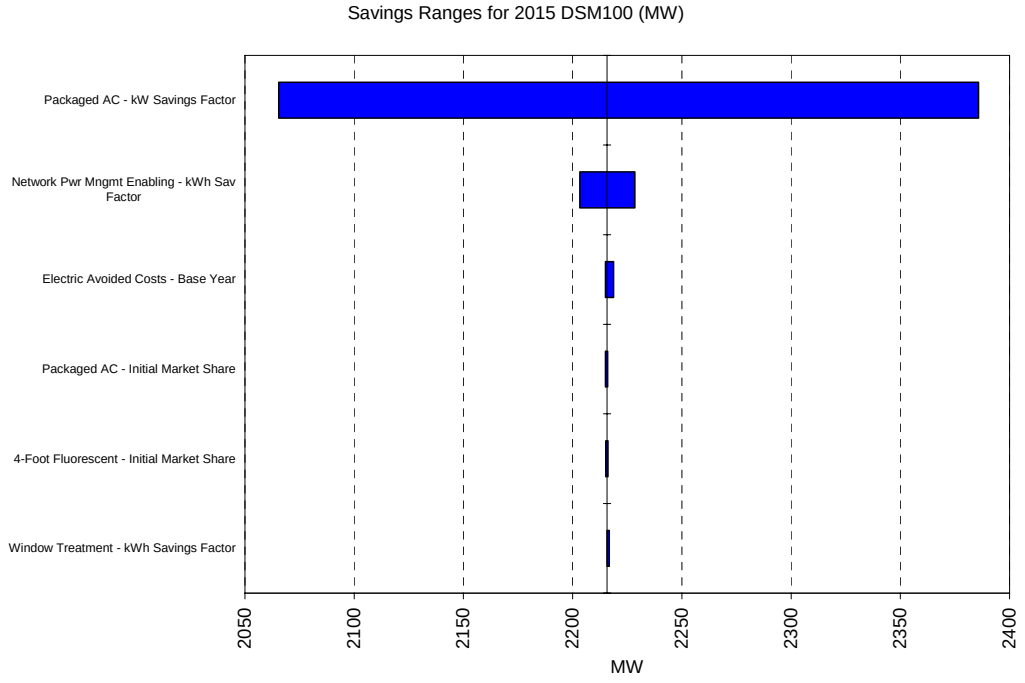


Figure 26. Commercial Sector Potential for Demand Reductions – Key Sensitivities



7. Conclusions

The technical potential for improving electricity efficiency in Ontario, as compared with current electricity consumption of 142 TW.hours, is about 37 TW.hours, or 26% of current consumption. Compared to the utility's avoided cost, we estimate 30 TW.hours of this potential is economic – 20% of the current level of consumption. These are theoretical potentials, in the sense that they are a measure of the efficiency improvement that would occur compared to *current* consumption if one could instantly implement the efficiency improvements. There is no allowance in these estimates for factors such as stock turnover rates or for the decision-making processes that determine the efficiency improvements that are practically achievable. On the other hand, the technical and economic potential estimates also do not take into account the additional savings opportunities that are created by the growth in the demand for electricity. The finding that there is an economic potential to reduce electricity consumption by 20% is typical of this type of calculation. While not an estimate that should be applied directly to the forecast level of electricity demand, it nevertheless suggests there may be an economic potential to reduce electricity consumption relative to the IESO/Navigant forecast by about 35 TW.hours of energy and 7 GW of demand.

Aside from the uncertainty in the forecast itself, estimates of efficiency potential in Ontario are also hampered by the sketchy information that is available on the current pattern of electricity use in Ontario and on current saturation levels and market shares of energy efficient technologies. Notwithstanding that uncertainty, different approaches to the question of how much CDM potential exists relative to that forecast, and how much of it is achievable, yield reasonably consistent results.

Estimates from other North American jurisdictions indicate an economic potential in the range of 10-30% for the residential sector, 13-35% in the commercial sector, and 6-32% in the industrial sector, with the portion that is deemed in these studies to be practically achievable ranging from 40-60% of the economic potential. In comparison, a review of actual historical performance of CDM programs in other jurisdictions indicates achieved reductions in electricity demand vary from as low as 2% to a maximum of 16%.

This last figure compares with the results of our EEPM analysis that indicate *achievable* efficiency gains through CDM programs are in the range of 10-16% relative to the IESO/Navigant forecast, with the 16% value representing the percent savings that could be achieved by sustained and aggressive CDM programs (incentives up to 100% of the measure cost). These ranges represent overall average efficiency gains across all end uses, including some (like electric baseboard heating) where the potential for efficiency improvement is limited and others, like commercial lighting, where the potential savings are quite high. This underscores the way in which the mix of end uses that are assumed to comprise the forecast can have a large effect on the achievable CDM potential. A different forecast or a different disaggregation of the forecast would yield a different assessment of CDM potential.

Some other key conclusions from our analysis:

- The efficiency potential is not evenly distributed across sectors or end uses, with the greatest potential for reducing future electricity use residing in the commercial sector, followed by the industrial sector. Lighting (commercial, residential and industrial) and commercial building air conditioning together comprising fully half the achievable potential for energy savings and these same two end uses account for the lion's share of the peak demand impact of the achievable efficiency potential.

- The estimate of efficiency potential is very sensitive to current technology saturations and market shares as these determine both how much high efficiency equipment is already in place and at what rate it is being adopted without incentives and CDM programs.

- Over the long term, the difference in electricity demand with and without CDM programs converges as it is assumed that the cost-effective electricity efficient technologies will eventually, albeit gradually, penetrate the market. Considering the extent to which supply capacity will be taken out of service in Ontario in the short to medium term, the ability of CDM programs to deliver savings on that same time line is potentially very important.

- The type of single line projection represented by the IESO/Navigant forecast used as the reference point for this CDM assessment does not lend itself to the type of bottom-up, integrated analysis of electricity demand patterns and CDM potential needed to reduce the uncertainty and associated risk associated with estimates presented here.

- In all the CDM scenarios analyzed, the program benefits far outweigh the costs from both the participant and utility perspectives. The program benefit/cost ratios decline for the utility as they increase for the participants, but are strongly positive from both perspectives under all scenarios. Net benefits to participants range from $5.7 billion to $21.3 billion.

Appendix A

Base Forecast Details

Residential End Use Forecast (MWh)

Year	Central AC/HP	Room AC	Heating	Sec Heating	Hot Water	Refrigerator	Freezer	Electric Dryer	DishWash	Cooking	Electronics	ElecMotors	ElecHeating Elements, PC, TV, OtherAppl	Furnace Fan	Lighting	ClothesWash	Total
2003	2,625,012	291,668	11,497,450	-	7,255,950	3,884,314	1,269,922	2,597,421	141,037	2,837,667	-	-	7,359,148	-	7,327,156	224,162	**47,310,906**
2004	2,367,546	263,061	11,663,028	-	7,264,843	4,170,595	1,451,867	2,541,116	143,722	2,754,980	-	-	6,987,509	-	7,107,072	226,413	**46,941,752**
2005	1,733,006	192,556	10,764,283	-	6,596,049	4,577,275	1,848,919	2,220,342	141,597	2,346,390	-	-	5,597,921	-	6,000,116	211,591	**42,230,046**
2006	1,745,465	193,941	10,691,212	-	6,476,302	4,504,489	1,822,824	2,198,382	140,938	2,343,609	-	-	5,666,024	-	5,992,789	210,162	**41,986,136**
2007	1,758,013	195,335	10,618,637	-	6,358,729	4,432,860	1,797,097	2,176,640	140,282	2,340,830	-	-	5,734,955	-	5,985,472	208,742	**41,747,592**
2008	1,770,651	196,739	10,546,555	-	6,243,290	4,362,370	1,771,733	2,155,113	139,629	2,338,055	-	-	5,804,725	-	5,978,163	207,332	**41,514,356**
2009	1,783,380	198,153	10,474,962	-	6,129,947	4,293,001	1,746,727	2,133,798	138,980	2,335,283	-	-	5,875,344	-	5,970,863	205,932	**41,286,371**
2010	1,796,201	199,578	10,403,855	-	6,018,662	4,224,735	1,722,074	2,112,695	138,333	2,332,515	-	-	5,946,822	-	5,963,572	204,541	**41,063,583**
2011	1,809,114	201,013	10,333,231	-	5,909,397	4,157,555	1,697,769	2,091,800	137,690	2,329,750	-	-	6,019,170	-	5,956,289	203,160	**40,845,936**
2012	1,822,120	202,458	10,263,087	-	5,802,115	4,091,442	1,673,807	2,071,112	137,049	2,326,988	-	-	6,092,397	-	5,949,016	201,788	**40,633,378**
2013	1,835,219	203,913	10,193,418	-	5,696,781	4,026,382	1,650,183	2,050,628	136,411	2,324,229	-	-	6,166,516	-	5,941,752	200,425	**40,425,857**
2014	1,848,412	205,379	10,124,222	-	5,593,360	3,962,355	1,626,893	2,030,347	135,777	2,321,474	-	-	6,241,536	-	5,934,496	199,071	**40,223,323**
2015	1,861,701	206,856	10,055,496	-	5,491,816	3,899,347	1,603,931	2,010,267	135,145	2,318,722	-	-	6,317,469	-	5,927,250	197,727	**40,025,725**
2016	1,875,084	208,343	9,987,237	-	5,392,115	3,837,341	1,581,293	1,990,385	134,516	2,315,973	-	-	6,394,326	-	5,920,012	196,391	**39,833,017**
2017	1,888,564	209,840	9,919,441	-	5,294,225	3,776,321	1,558,975	1,970,700	133,891	2,313,227	-	-	6,472,118	-	5,912,783	195,065	**39,645,149**
2018	1,902,141	211,349	9,852,105	-	5,198,112	3,716,271	1,536,972	1,951,209	133,268	2,310,485	-	-	6,550,856	-	5,905,563	193,747	**39,462,077**
2019	1,915,816	212,868	9,785,227	-	5,103,743	3,657,176	1,515,279	1,931,912	132,648	2,307,746	-	-	6,630,552	-	5,898,351	192,439	**39,283,756**
2020	1,929,588	214,399	9,718,802	-	5,011,088	3,599,021	1,493,893	1,912,805	132,030	2,305,010	-	-	6,711,217	-	5,891,149	191,139	**39,110,141**
2021	1,943,460	215,940	9,652,828	-	4,920,115	3,541,790	1,472,808	1,893,887	131,416	2,302,277	-	-	6,792,864	-	5,883,955	189,848	**38,941,189**
2022	1,957,432	217,492	9,587,302	-	4,830,793	3,485,470	1,452,021	1,875,156	130,805	2,299,548	-	-	6,875,505	-	5,876,770	188,566	**38,776,860**
2023	1,971,504	219,056	9,522,221	-	4,743,093	3,430,045	1,431,528	1,856,610	130,196	2,296,822	-	-	6,959,150	-	5,869,594	187,292	**38,617,111**
2024	1,985,677	220,631	9,457,582	-	4,656,985	3,375,501	1,411,323	1,838,248	129,591	2,294,099	-	-	7,043,814	-	5,862,427	186,027	**38,461,904**
2025	1,999,952	222,217	9,393,381	-	4,572,440	3,321,825	1,391,404	1,820,068	128,988	2,291,379	-	-	7,129,507	-	5,855,268	184,771	**38,311,200**

Residential End Use Forecast (Peak MW)

Year	Central AC/HP	Room AC	Heating	SecHeating	HotWater	Refrigerator	Freezer	Electric Dryer	DishWash	Cooking	Electronics	ElecMotors	ElecHeating Elements, PC, TV, OtherAppl	Furnace Fan	Lighting	ClothesWash	TOTAL
2003	4,690.00	521.11	-	-	473.67	365.51	110.64	57.73	12.48	144.68	-	-	531.79	-	53.36	4.98	**6,965.96**
2004	4,542.89	504.77	-	-	509.33	421.48	135.85	60.66	13.66	150.85	-	-	542.29	-	55.58	5.40	**6,942.76**
2005	3,523.90	391.54	-	-	490.06	490.21	183.33	56.16	14.26	136.15	-	-	460.39	-	49.73	5.35	**5,801.08**
2006	3,537.70	393.08	-	-	479.60	480.84	180.16	55.43	14.15	135.55	-	-	464.47	-	49.50	5.30	**5,795.78**
2007	3,549.21	394.36	-	-	469.05	471.35	176.92	54.66	14.03	134.86	-	-	468.29	-	49.25	5.24	**5,787.22**
2008	3,562.09	395.79	-	-	458.91	462.21	173.81	53.93	13.91	134.22	-	-	472.31	-	49.02	5.19	**5,781.39**
2009	3,587.18	398.58	-	-	450.51	454.80	171.33	53.39	13.85	134.04	-	-	477.98	-	48.95	5.15	**5,795.76**
2010	3,577.72	397.52	-	-	438.02	443.20	167.26	52.35	13.65	132.58	-	-	479.08	-	48.41	5.07	**5,754.86**
2011	3,585.00	398.33	-	-	427.87	433.92	164.06	51.56	13.51	131.74	-	-	482.43	-	48.11	5.01	**5,741.54**
2012	3,591.41	399.05	-	-	417.85	424.73	160.87	50.78	13.38	130.88	-	-	485.68	-	47.79	4.95	**5,727.36**
2013	3,598.63	399.85	-	-	408.15	415.83	157.79	50.02	13.25	130.06	-	-	489.06	-	47.49	4.89	**5,715.00**
2014	3,602.94	400.33	-	-	398.36	406.78	154.64	49.23	13.11	129.13	-	-	492.06	-	47.15	4.83	**5,698.54**
2015	3,621.27	402.36	-	-	390.31	399.48	152.14	48.64	13.02	128.71	-	-	497.01	-	46.99	4.78	**5,704.71**
2016	3,629.19	403.24	-	-	381.32	391.17	149.24	47.92	12.89	127.91	-	-	500.56	-	46.70	4.73	**5,694.88**
2017	3,636.81	404.09	-	-	372.51	383.01	146.39	47.21	12.77	127.12	-	-	504.09	-	46.41	4.67	**5,685.06**
2018	3,644.13	404.90	-	-	363.86	374.98	143.59	46.50	12.65	126.31	-	-	507.60	-	46.11	4.62	**5,675.25**
2019	3,651.17	405.69	-	-	355.39	367.09	140.82	45.80	12.52	125.51	-	-	511.09	-	45.82	4.56	**5,665.46**
2020	3,657.94	406.44	-	-	347.09	359.34	138.10	45.11	12.40	124.69	-	-	514.57	-	45.52	4.51	**5,655.70**
2021	3,664.44	407.16	-	-	338.96	351.73	135.42	44.42	12.27	123.88	-	-	518.03	-	45.22	4.45	**5,645.98**
2022	3,670.68	407.85	-	-	330.99	344.25	132.78	43.74	12.15	123.06	-	-	521.48	-	44.92	4.40	**5,636.29**
2023	3,676.67	408.52	-	-	323.19	336.90	130.18	43.07	12.03	122.23	-	-	524.91	-	44.61	4.34	**5,626.66**
2024	3,682.42	409.16	-	-	315.55	329.69	127.63	42.41	11.90	121.40	-	-	528.33	-	44.31	4.29	**5,617.09**
2025	3,687.93	409.77	-	-	308.07	322.62	125.12	41.75	11.78	120.58	-	-	531.73	-	44.01	4.24	**5,607.59**

Commercial End Use Forecast (MWh)

	Years	Heat	Cool	Vent	Water	Cook	Refrig	Xlit	Ilit	Ofeq	Misc	Total
Arts, Entertainment and Recreation	2004	22,869	31,115	208,884	3,611	-	78,331	49,316	303,781	-	234,994	932,901
	2005	22,920	31,184	209,347	3,619	-	78,505	49,425	304,455	-	235,516	934,972
	2006	23,561	32,056	215,202	3,720	-	80,701	50,808	312,970	-	242,103	961,120
	2007	24,219	32,952	221,221	3,825	-	82,958	52,229	321,723	-	248,873	987,999
	2008	24,897	33,874	227,408	3,931	-	85,278	53,689	330,720	-	255,833	1,015,630
	2009	25,593	34,821	233,767	4,041	-	87,663	55,191	339,969	-	262,988	1,044,034
	2010	26,309	35,795	240,305	4,154	-	90,114	56,734	349,477	-	270,343	1,073,232
	2011	27,045	36,796	247,026	4,271	-	92,635	58,321	359,251	-	277,904	1,103,247
	2012	27,801	37,825	253,934	4,390	-	95,225	59,952	369,298	-	285,676	1,134,101
	2013	28,578	38,883	261,036	4,513	-	97,888	61,629	379,626	-	293,665	1,165,818
	2014	29,378	39,970	268,336	4,639	-	100,626	63,352	390,243	-	301,878	1,198,422
	2015	30,199	41,088	275,841	4,769	-	103,440	65,124	401,157	-	310,321	1,231,938
	2016	31,044	42,237	283,555	4,902	-	106,333	66,945	412,376	-	318,999	1,266,392
	2017	31,912	43,419	291,485	5,039	-	109,307	68,817	423,908	-	327,921	1,301,808
	2018	32,805	44,633	299,637	5,180	-	112,364	70,742	435,764	-	337,092	1,338,216
	2019	33,722	45,881	308,017	5,325	-	115,506	72,720	447,951	-	346,519	1,375,641
	2020	34,665	47,164	316,631	5,474	-	118,737	74,754	460,478	-	356,210	1,414,113
	2021	35,635	48,483	325,486	5,627	-	122,057	76,845	473,356	-	366,172	1,453,661
	2022	36,631	49,839	334,589	5,784	-	125,471	78,994	486,595	-	376,413	1,494,316
	2023	37,656	51,233	343,946	5,946	-	128,980	81,203	500,203	-	386,940	1,536,107
	2024	38,709	52,666	353,565	6,113	-	132,587	83,474	514,192	-	397,761	1,579,066
	2025	39,791	54,139	363,453	6,283	-	136,295	85,809	528,572	-	408,885	1,623,228
Educational Services	2004	108,917	398,253	235,604	2,079	8,019	88,352	126,966	782,100	64,150	353,261	2,167,701
	2005	99,480	363,748	215,191	1,899	7,324	80,697	115,966	714,337	58,592	322,654	1,979,887
	2006	101,150	369,855	218,804	1,931	7,447	82,051	117,913	726,330	59,576	328,071	2,013,127
	2007	102,848	376,064	222,477	1,963	7,572	83,429	119,892	738,524	60,576	333,579	2,046,924
	2008	104,575	382,378	226,212	1,996	7,699	84,830	121,905	750,923	61,593	339,179	2,081,290
	2009	106,331	388,797	230,010	2,030	7,828	86,254	123,952	763,530	62,627	344,873	2,116,232
	2010	108,116	395,325	233,872	2,064	7,960	87,702	126,033	776,349	63,678	350,663	2,151,761
	2011	109,931	401,962	237,798	2,098	8,093	89,174	128,149	789,383	64,747	356,551	2,187,886
	2012	111,776	408,710	241,791	2,134	8,229	90,671	130,300	802,635	65,834	362,537	2,224,618
	2013	113,653	415,572	245,850	2,170	8,367	92,194	132,488	816,110	66,940	368,623	2,261,966
	2014	115,561	422,549	249,977	2,206	8,508	93,742	134,712	829,812	68,063	374,812	2,299,942
	2015	117,501	429,643	254,174	2,243	8,651	95,315	136,974	843,743	69,206	381,104	2,338,555
	2016	119,474	436,856	258,441	2,281	8,796	96,916	139,273	857,909	70,368	387,503	2,377,816
	2017	121,480	444,190	262,780	2,319	8,944	98,543	141,611	872,312	71,549	394,008	2,417,737
	2018	123,519	451,647	267,192	2,358	9,094	100,197	143,989	886,957	72,751	400,623	2,458,327
	2019	125,593	459,230	271,678	2,397	9,247	101,879	146,406	901,848	73,972	407,349	2,499,600
	2020	127,702	466,940	276,239	2,438	9,402	103,590	148,864	916,989	75,214	414,188	2,541,565
	2021	129,846	474,779	280,877	2,479	9,560	105,329	151,363	932,384	76,477	421,142	2,584,234
	2022	132,025	482,750	285,592	2,520	9,720	107,097	153,905	948,037	77,761	428,212	2,627,620
	2023	134,242	490,855	290,387	2,563	9,883	108,895	156,488	963,954	79,066	435,401	2,671,735
	2024	136,496	499,096	295,262	2,606	10,049	110,723	159,116	980,137	80,394	442,711	2,716,590
	2025	138,787	507,475	300,219	2,649	10,218	112,582	161,787	996,592	81,743	450,144	2,762,198
Information & Cultural Industries	2004	16,659	19,670	152,143	2,630	-	57,054	35,920	221,263	-	171,161	676,500
	2005	16,488	19,467	150,577	2,603	-	56,466	35,550	218,986	-	169,399	669,537
	2006	16,896	19,949	154,305	2,668	-	57,864	36,430	224,406	-	173,593	686,110
	2007	17,314	20,443	158,124	2,734	-	59,297	37,332	229,961	-	177,890	703,094
	2008	17,743	20,949	162,038	2,801	-	60,764	38,256	235,653	-	182,293	720,498
	2009	18,182	21,467	166,049	2,871	-	62,268	39,203	241,486	-	186,805	738,332
	2010	18,632	21,999	170,159	2,942	-	63,810	40,173	247,464	-	191,429	756,608
	2011	19,093	22,543	174,371	3,015	-	65,389	41,168	253,589	-	196,168	775,336
	2012	19,566	23,101	178,688	3,089	-	67,008	42,187	259,866	-	201,023	794,528
	2013	20,050	23,673	183,111	3,166	-	68,666	43,231	266,299	-	205,999	814,195
	2014	20,546	24,259	187,643	3,244	-	70,366	44,301	272,891	-	211,099	834,349
	2015	21,055	24,860	192,288	3,324	-	72,108	45,398	279,645	-	216,324	855,002
	2016	21,576	25,475	197,048	3,407	-	73,893	46,521	286,567	-	221,679	876,166
	2017	22,110	26,106	201,925	3,491	-	75,722	47,673	293,661	-	227,166	897,854
	2018	22,658	26,752	206,923	3,577	-	77,596	48,853	300,930	-	232,789	920,078
	2019	23,218	27,414	212,045	3,666	-	79,517	50,062	308,379	-	238,551	942,853
	2020	23,793	28,093	217,294	3,757	-	81,485	51,301	316,012	-	244,456	966,192
	2021	24,382	28,788	222,673	3,850	-	83,502	52,571	323,834	-	250,507	990,108
	2022	24,986	29,501	228,185	3,945	-	85,569	53,873	331,850	-	256,708	1,014,616
	2023	25,604	30,231	233,833	4,043	-	87,687	55,206	340,065	-	263,062	1,039,731
	2024	26,238	30,979	239,621	4,143	-	89,858	56,573	348,482	-	269,574	1,065,467
	2025	26,887	31,746	245,552	4,245	-	92,082	57,973	357,108	-	276,246	1,091,841
Accommodation & Food Services	2004	30,843	1,828,603	176,138	12,684	85,171	66,052	124,817	768,862	681,365	1,135,033	4,909,569
	2005	34,596	2,051,125	197,573	14,227	95,535	74,090	140,006	862,425	764,280	1,273,155	5,507,012
	2006	35,119	2,082,081	200,554	14,442	96,977	75,208	142,119	875,441	775,815	1,292,369	5,590,126
	2007	35,649	2,113,505	203,581	14,660	98,440	76,343	144,264	888,653	787,524	1,311,874	5,674,493
	2008	36,187	2,145,402	206,654	14,881	99,926	77,495	146,441	902,065	799,410	1,331,674	5,760,135
	2009	36,733	2,177,781	209,773	15,106	101,434	78,665	148,652	915,679	811,474	1,351,772	5,847,068
	2010	37,287	2,210,649	212,939	15,334	102,965	79,852	150,895	929,499	823,722	1,372,173	5,935,314
	2011	37,850	2,244,013	216,152	15,565	104,519	81,057	153,172	943,527	836,153	1,392,882	6,024,892
	2012	38,421	2,277,880	219,415	15,800	106,097	82,280	155,484	957,767	848,773	1,413,904	6,115,821
	2013	39,001	2,312,259	222,726	16,039	107,698	83,522	157,831	972,222	861,583	1,435,243	6,208,123
	2014	39,590	2,347,156	226,087	16,281	109,323	84,783	160,213	986,895	874,586	1,456,904	6,301,818
	2015	40,187	2,382,580	229,500	16,527	110,973	86,062	162,631	1,001,790	887,786	1,478,892	6,396,927
	2016	40,794	2,418,539	232,963	16,776	112,648	87,361	165,085	1,016,909	901,184	1,501,212	6,493,472
	2017	41,409	2,455,040	236,479	17,029	114,348	88,680	167,577	1,032,257	914,785	1,523,869	6,591,473
	2018	42,034	2,492,092	240,048	17,286	116,074	90,018	170,106	1,047,836	928,592	1,546,868	6,690,954
	2019	42,669	2,529,704	243,671	17,547	117,826	91,377	172,673	1,063,650	942,606	1,570,213	6,791,936
	2020	43,313	2,567,883	247,349	17,812	119,604	92,756	175,279	1,079,703	956,832	1,593,912	6,894,442
	2021	43,966	2,606,638	251,082	18,081	121,409	94,156	177,925	1,095,998	971,273	1,617,967	6,998,495
	2022	44,630	2,645,978	254,871	18,354	123,241	95,577	180,610	1,112,539	985,932	1,642,386	7,104,118
	2023	45,303	2,685,912	258,718	18,631	125,101	97,019	183,336	1,129,330	1,000,812	1,667,174	7,211,336
	2024	45,987	2,726,449	262,622	18,912	126,990	98,483	186,103	1,146,374	1,015,916	1,692,335	7,320,172
	2025	46,681	2,767,597	266,586	19,197	128,906	99,970	188,911	1,163,676	1,031,249	1,717,876	7,430,650

Commercial End Use Forecast (MWh)

	Years	Heat	Cool	Vent	Water	Cook	Refrig	Xlit	Ilit	Ofeq	Misc	Total
Health Care & Social Assistance	2004	82,792	746,005	332,357	11,110	23,415	124,634	181,378	1,117,269	187,319	631,466	3,437,745
	2005	86,787	781,998	348,393	11,646	24,545	130,647	190,129	1,171,175	196,357	661,933	3,603,610
	2006	88,283	795,478	354,398	11,847	24,968	132,899	193,406	1,191,364	199,742	673,343	3,665,728
	2007	89,804	809,190	360,507	12,051	25,398	135,190	196,740	1,211,900	203,185	684,950	3,728,917
	2008	91,352	823,139	366,722	12,259	25,836	137,521	200,131	1,232,790	206,687	696,757	3,793,195
	2009	92,927	837,328	373,043	12,470	26,281	139,891	203,581	1,254,041	210,250	708,767	3,858,580
	2010	94,529	851,762	379,473	12,685	26,734	142,303	207,091	1,275,657	213,874	720,985	3,925,093
	2011	96,158	866,444	386,015	12,904	27,195	144,755	210,660	1,297,647	217,561	733,413	3,992,753
	2012	97,816	881,379	392,669	13,126	27,664	147,251	214,292	1,320,015	221,311	746,055	4,061,578
	2013	99,502	896,572	399,437	13,353	28,141	149,789	217,985	1,342,769	225,126	758,916	4,131,590
	2014	101,217	912,027	406,323	13,583	28,626	152,371	221,743	1,365,915	229,007	771,998	4,202,809
	2015	102,962	927,748	413,327	13,817	29,119	154,998	225,565	1,389,460	232,954	785,305	4,275,256
	2016	104,737	943,741	420,452	14,055	29,621	157,669	229,454	1,413,411	236,970	798,842	4,348,951
	2017	106,542	960,008	427,699	14,297	30,132	160,387	233,409	1,437,775	241,055	812,612	4,423,917
	2018	108,379	976,557	435,072	14,544	30,651	163,152	237,432	1,462,559	245,210	826,620	4,500,175
	2019	110,247	993,390	442,571	14,794	31,180	165,964	241,525	1,487,770	249,437	840,869	4,577,748
	2020	112,147	1,010,514	450,200	15,049	31,717	168,825	245,688	1,513,416	253,737	855,363	4,656,657
	2021	114,080	1,027,933	457,961	15,309	32,264	171,735	249,923	1,539,504	258,110	870,108	4,736,927
	2022	116,047	1,045,652	465,855	15,573	32,820	174,696	254,232	1,566,041	262,560	885,106	4,818,581
	2023	118,047	1,063,677	473,885	15,841	33,386	177,707	258,614	1,593,036	267,086	900,363	4,901,642
	2024	120,082	1,082,012	482,054	16,114	33,961	180,770	263,072	1,620,496	271,690	915,884	4,986,135
	2025	122,152	1,100,663	490,363	16,392	34,547	183,886	267,607	1,648,430	276,373	931,671	5,072,084
Wholesale Trade	2004	37,403	590,925	272,538	1,450	12,464	102,202	104,525	643,864	99,715	443,713	2,308,800
	2005	39,304	620,954	286,388	1,524	13,098	107,396	109,837	676,583	104,782	466,261	2,426,126
	2006	39,357	621,795	286,776	1,526	13,115	107,541	109,985	677,500	104,924	466,893	2,429,412
	2007	39,411	622,637	287,164	1,528	13,133	107,687	110,134	678,417	105,066	467,525	2,432,702
	2008	39,464	623,480	287,553	1,530	13,151	107,832	110,284	679,336	105,208	468,158	2,435,997
	2009	39,518	624,324	287,943	1,532	13,169	107,978	110,433	680,256	105,351	468,792	2,439,296
	2010	39,571	625,170	288,333	1,534	13,187	108,125	110,582	681,177	105,493	469,427	2,442,599
	2011	39,625	626,017	288,723	1,536	13,205	108,271	110,732	682,100	105,636	470,063	2,445,907
	2012	39,678	626,864	289,114	1,538	13,222	108,418	110,882	683,024	105,779	470,700	2,449,220
	2013	39,732	627,713	289,506	1,540	13,240	108,565	111,032	683,949	105,922	471,337	2,452,537
	2014	39,786	628,563	289,898	1,542	13,258	108,712	111,183	684,875	106,066	471,976	2,455,859
	2015	39,840	629,415	290,290	1,545	13,276	108,859	111,333	685,802	106,210	472,615	2,459,185
	2016	39,894	630,267	290,684	1,547	13,294	109,006	111,484	686,731	106,353	473,255	2,462,515
	2017	39,948	631,121	291,077	1,549	13,312	109,154	111,635	687,661	106,497	473,896	2,465,850
	2018	40,002	631,976	291,471	1,551	13,330	109,302	111,786	688,593	106,642	474,538	2,469,190
	2019	40,056	632,831	291,866	1,553	13,348	109,450	111,938	689,525	106,786	475,180	2,472,534
	2020	40,110	633,688	292,261	1,555	13,366	109,598	112,089	690,459	106,931	475,824	2,475,883
	2021	40,165	634,547	292,657	1,557	13,384	109,746	112,241	691,394	107,076	476,468	2,479,236
	2022	40,219	635,406	293,054	1,559	13,403	109,895	112,393	692,331	107,221	477,114	2,482,593
	2023	40,273	636,267	293,451	1,561	13,421	110,044	112,545	693,268	107,366	477,760	2,485,956
	2024	40,328	637,128	293,848	1,563	13,439	110,193	112,698	694,207	107,511	478,407	2,489,323
	2025	40,383	637,991	294,246	1,566	13,457	110,342	112,850	695,147	107,657	479,055	2,492,694
Offices	2004	604,696	6,361,692	2,062,286	11,093	308,105	773,357	1,725,605	10,629,559	2,464,837	5,709,223	30,650,452
	2005	620,146	6,524,229	2,114,976	11,376	315,977	793,116	1,769,693	10,901,137	2,527,812	5,855,090	31,433,551
	2006	632,157	6,650,597	2,155,941	11,597	322,097	808,478	1,803,971	11,112,282	2,576,774	5,968,498	32,042,391
	2007	644,402	6,779,413	2,197,700	11,821	328,335	824,137	1,838,912	11,327,517	2,626,684	6,084,102	32,663,023
	2008	656,883	6,910,724	2,240,267	12,050	334,695	840,100	1,874,530	11,546,921	2,677,560	6,201,946	33,295,676
	2009	669,606	7,044,579	2,283,659	12,284	341,178	856,372	1,910,838	11,770,574	2,729,422	6,322,072	33,940,583
	2010	682,576	7,181,026	2,327,891	12,521	347,786	872,959	1,947,849	11,998,560	2,782,288	6,444,525	34,597,982
	2011	695,797	7,320,116	2,372,981	12,764	354,522	889,868	1,985,577	12,230,961	2,836,179	6,569,349	35,268,114
	2012	709,274	7,461,900	2,418,943	13,011	361,389	907,104	2,024,036	12,467,864	2,891,113	6,696,592	35,951,225
	2013	723,012	7,606,430	2,465,796	13,263	368,389	924,673	2,063,240	12,709,355	2,947,111	6,826,298	36,647,568
	2014	737,016	7,753,760	2,513,556	13,520	375,524	942,584	2,103,203	12,955,524	3,004,194	6,958,518	37,357,399
	2015	751,291	7,903,944	2,562,241	13,782	382,798	960,841	2,143,940	13,206,460	3,062,383	7,093,298	38,080,978
	2016	765,843	8,057,036	2,611,870	14,049	390,212	979,451	2,185,466	13,462,258	3,121,698	7,230,689	38,818,572
	2017	780,677	8,213,093	2,662,459	14,321	397,770	998,422	2,227,797	13,723,009	3,182,163	7,370,741	39,570,453
	2018	795,798	8,372,174	2,714,029	14,598	405,475	1,017,761	2,270,947	13,988,812	3,243,799	7,513,505	40,336,897
	2019	811,212	8,534,335	2,766,597	14,881	413,328	1,037,474	2,314,933	14,259,762	3,306,628	7,659,035	41,118,186
	2020	826,924	8,699,637	2,820,183	15,169	421,334	1,057,569	2,359,771	14,535,961	3,370,674	7,807,384	41,914,608
	2021	842,941	8,868,141	2,874,808	15,463	429,495	1,078,053	2,405,478	14,817,510	3,435,961	7,958,606	42,726,456
	2022	859,268	9,039,909	2,930,490	15,763	437,814	1,098,934	2,452,070	15,104,512	3,502,513	8,112,757	43,554,029
	2023	875,911	9,215,004	2,987,251	16,068	446,294	1,120,219	2,499,564	15,397,072	3,570,353	8,269,893	44,397,632
	2024	892,877	9,393,491	3,045,112	16,379	454,938	1,141,917	2,547,979	15,695,300	3,639,508	8,430,074	45,257,574
	2025	910,171	9,575,434	3,104,093	16,697	463,750	1,164,035	2,597,331	15,999,304	3,710,002	8,593,357	46,134,172
Retail Trade	2004	105,021	1,696,449	731,998	3,949	33,934	274,499	255,883	1,576,213	271,470	1,196,769	6,146,185
	2005	109,837	1,774,233	765,561	4,130	35,490	287,085	267,615	1,648,484	283,917	1,251,642	6,427,993
	2006	110,192	1,779,964	768,034	4,143	35,604	288,013	268,480	1,653,809	284,834	1,255,685	6,448,758
	2007	110,548	1,785,714	770,515	4,156	35,719	288,943	269,347	1,659,151	285,754	1,259,742	6,469,590
	2008	110,905	1,791,483	773,004	4,170	35,835	289,877	270,217	1,664,511	286,677	1,263,811	6,490,490
	2009	111,263	1,797,270	775,501	4,183	35,950	290,813	271,090	1,669,888	287,604	1,267,894	6,511,457
	2010	111,622	1,803,076	778,006	4,197	36,067	291,752	271,966	1,675,283	288,533	1,271,990	6,532,491
	2011	111,983	1,808,901	780,520	4,210	36,183	292,695	272,844	1,680,695	289,465	1,276,099	6,553,594
	2012	112,345	1,814,744	783,041	4,224	36,300	293,640	273,726	1,686,124	290,400	1,280,221	6,574,765
	2013	112,708	1,820,607	785,571	4,238	36,417	294,589	274,610	1,691,571	291,338	1,284,357	6,596,004
	2014	113,072	1,826,488	788,108	4,251	36,535	295,541	275,497	1,697,035	292,279	1,288,506	6,617,312
	2015	113,437	1,832,388	790,654	4,265	36,653	296,495	276,387	1,702,517	293,223	1,292,668	6,638,689
	2016	113,803	1,838,308	793,208	4,279	36,771	297,453	277,280	1,708,017	294,171	1,296,844	6,660,135
	2017	114,171	1,844,246	795,771	4,293	36,890	298,414	278,176	1,713,535	295,121	1,301,033	6,681,650
	2018	114,540	1,850,204	798,342	4,307	37,009	299,378	279,074	1,719,070	296,074	1,305,236	6,703,234
	2019	114,910	1,856,181	800,921	4,320	37,129	300,345	279,976	1,724,624	297,031	1,309,453	6,724,889
	2020	115,281	1,862,177	803,508	4,334	37,249	301,315	280,880	1,730,195	297,990	1,313,683	6,746,613
	2021	115,654	1,868,193	806,104	4,348	37,369	302,289	281,788	1,735,784	298,953	1,317,927	6,768,407
	2022	116,027	1,874,228	808,708	4,362	37,490	303,265	282,698	1,741,392	299,919	1,322,184	6,790,272
	2023	116,402	1,880,282	811,320	4,377	37,611	304,245	283,611	1,747,017	300,887	1,326,455	6,812,208
	2024	116,778	1,886,356	813,941	4,391	37,732	305,228	284,527	1,752,661	301,859	1,330,740	6,834,214
	2025	117,155	1,892,450	816,570	4,405	37,854	306,214	285,446	1,758,322	302,835	1,335,039	6,856,291

Commercial End Use Forecast (MWh)

	Years	Heat	Cool	Vent	Water	Cook	Refrig	Xlit	Ilit	Ofeq	Misc	Total
Transportation & Warehousing	2004	29,085	64,207	168,655	489	-	63,246	82,952	510,979	-	189,737	1,109,350
	2005	27,249	60,154	158,009	458	-	59,253	77,716	478,723	-	177,760	1,039,321
	2006	27,167	59,973	157,533	457	-	59,075	77,482	477,283	-	177,225	1,036,194
	2007	27,085	59,793	157,059	455	-	58,897	77,249	475,847	-	176,692	1,033,077
	2008	27,003	59,613	156,587	454	-	58,720	77,017	474,415	-	176,160	1,029,969
	2009	26,922	59,433	156,115	453	-	58,543	76,785	472,988	-	175,630	1,026,870
	2010	26,841	59,254	155,646	451	-	58,367	76,554	471,565	-	175,102	1,023,780
	2011	26,760	59,076	155,177	450	-	58,192	76,324	470,146	-	174,575	1,020,700
	2012	26,680	58,898	154,711	449	-	58,016	76,094	468,731	-	174,049	1,017,629
	2013	26,600	58,721	154,245	447	-	57,842	75,865	467,321	-	173,526	1,014,567
	2014	26,520	58,545	153,781	446	-	57,668	75,637	465,915	-	173,004	1,011,515
	2015	26,440	58,368	153,318	445	-	57,494	75,409	464,513	-	172,483	1,008,471
	2016	26,360	58,193	152,857	443	-	57,321	75,182	463,116	-	171,964	1,005,437
	2017	26,281	58,018	152,397	442	-	57,149	74,956	461,722	-	171,447	1,002,412
	2018	26,202	57,843	151,939	441	-	56,977	74,731	460,333	-	170,931	999,396
	2019	26,123	57,669	151,482	439	-	56,806	74,506	458,948	-	170,417	996,389
	2020	26,045	57,496	151,026	438	-	56,635	74,282	457,567	-	169,904	993,391
	2021	25,966	57,323	150,571	437	-	56,464	74,058	456,191	-	169,393	990,403
	2022	25,888	57,150	150,118	435	-	56,294	73,835	454,818	-	168,883	987,423
	2023	25,810	56,978	149,667	434	-	56,125	73,613	453,450	-	168,375	984,452
	2024	25,732	56,807	149,216	433	-	55,956	73,392	452,085	-	167,868	981,490
	2025	25,655	56,636	148,767	431	-	55,788	73,171	450,725	-	167,363	978,537
Other Services	2004	19,399	110,910	78,940	528	-	29,602	27,955	172,201	-	88,807	528,342
	2005	19,533	111,676	79,485	532	-	29,807	28,148	173,390	-	89,421	531,991
	2006	19,703	112,646	80,175	537	-	30,066	28,393	174,896	-	90,197	536,612
	2007	19,874	113,624	80,872	541	-	30,327	28,639	176,415	-	90,981	541,273
	2008	20,046	114,611	81,574	546	-	30,590	28,888	177,947	-	91,771	545,974
	2009	20,220	115,607	82,283	551	-	30,856	29,139	179,493	-	92,568	550,716
	2010	20,396	116,611	82,997	556	-	31,124	29,392	181,052	-	93,372	555,500
	2011	20,573	117,624	83,718	560	-	31,394	29,647	182,624	-	94,183	560,325
	2012	20,752	118,645	84,445	565	-	31,667	29,905	184,211	-	95,001	565,192
	2013	20,932	119,676	85,179	570	-	31,942	30,165	185,811	-	95,826	570,101
	2014	21,114	120,715	85,919	575	-	32,220	30,427	187,425	-	96,659	575,052
	2015	21,297	121,764	86,665	580	-	32,499	30,691	189,052	-	97,498	580,047
	2016	21,482	122,822	87,418	585	-	32,782	30,957	190,695	-	98,345	585,085
	2017	21,669	123,888	88,177	590	-	33,066	31,226	192,351	-	99,199	590,167
	2018	21,857	124,964	88,943	595	-	33,354	31,498	194,022	-	100,061	595,293
	2019	22,047	126,050	89,715	601	-	33,643	31,771	195,707	-	100,930	600,464
	2020	22,239	127,145	90,495	606	-	33,935	32,047	197,407	-	101,806	605,679
	2021	22,432	128,249	91,281	611	-	34,230	32,325	199,121	-	102,691	610,940
	2022	22,627	129,363	92,074	616	-	34,528	32,606	200,851	-	103,583	616,247
	2023	22,823	130,487	92,873	622	-	34,827	32,889	202,595	-	104,482	621,599
	2024	23,021	131,620	93,680	627	-	35,130	33,175	204,355	-	105,390	626,998
	2025	23,221	132,763	94,494	633	-	35,435	33,463	206,130	-	106,305	632,444

Commercial Baseline Forecast (Peak MW)

	Years	Heat	Cool	Vent	Water	Cook	Refrig	Xlit	Ilit	Ofeq	Misc	Total
Arts, Entertainment and Recreation	2004	-	36.96	10.62	-	-	5.13	0.40	33.76	-	31.71	118.59
	2005	-	34.22	9.83	-	-	4.75	0.37	31.25	-	29.35	109.77
	2006	-	35.37	10.17	-	-	4.91	0.38	32.30	-	30.34	113.48
	2007	-	36.54	10.50	-	-	5.08	0.40	33.37	-	31.35	117.24
	2008	-	37.77	10.86	-	-	5.25	0.41	34.49	-	32.40	121.17
	2009	-	39.17	11.26	-	-	5.44	0.43	35.77	-	33.60	125.66
	2010	-	40.23	11.56	-	-	5.59	0.44	36.74	-	34.51	129.06
	2011	-	41.51	11.93	-	-	5.76	0.45	37.91	-	35.61	133.17
	2012	-	42.82	12.31	-	-	5.95	0.47	39.10	-	36.73	137.37
	2013	-	44.18	12.70	-	-	6.14	0.48	40.35	-	37.90	141.74
	2014	-	45.55	13.09	-	-	6.33	0.50	41.60	-	39.07	146.13
	2015	-	47.14	13.55	-	-	6.55	0.51	43.05	-	40.44	151.24
	2016	-	48.65	13.98	-	-	6.76	0.53	44.43	-	41.73	156.07
	2017	-	50.20	14.43	-	-	6.97	0.55	45.84	-	43.06	161.04
	2018	-	51.79	14.88	-	-	7.19	0.56	47.29	-	44.42	166.15
	2019	-	53.43	15.36	-	-	7.42	0.58	48.79	-	45.83	171.40
	2020	-	55.11	15.84	-	-	7.65	0.60	50.33	-	47.27	176.81
	2021	-	56.84	16.34	-	-	7.89	0.62	51.91	-	48.76	182.36
	2022	-	58.62	16.85	-	-	8.14	0.64	53.54	-	50.29	188.07
	2023	-	60.45	17.37	-	-	8.40	0.66	55.21	-	51.86	193.94
	2024	-	62.33	17.92	-	-	8.66	0.68	56.92	-	53.47	199.98
	2025	-	64.27	18.47	-	-	8.93	0.70	58.69	-	55.13	206.18
Educational Services	2004	-	207.45	19.39	0.27	1.49	6.20	1.04	91.57	7.44	40.98	375.83
	2005	-	175.00	16.36	0.23	1.26	5.23	0.87	77.25	6.28	34.57	317.04
	2006	-	178.95	16.72	0.23	1.29	5.34	0.89	78.99	6.42	35.35	324.20
	2007	-	182.87	17.09	0.24	1.32	5.46	0.91	80.72	6.56	36.13	331.30
	2008	-	186.95	17.47	0.24	1.35	5.58	0.93	82.52	6.71	36.93	338.68
	2009	-	191.76	17.92	0.25	1.38	5.73	0.96	84.64	6.88	37.88	347.39
	2010	-	194.80	18.21	0.25	1.40	5.82	0.97	85.99	6.99	38.48	352.91
	2011	-	198.82	18.58	0.26	1.43	5.94	0.99	87.76	7.13	39.28	360.19
	2012	-	202.87	18.96	0.26	1.46	6.06	1.01	89.55	7.28	40.08	367.53
	2013	-	207.05	19.35	0.27	1.49	6.18	1.03	91.39	7.43	40.90	375.10
	2014	-	211.14	19.73	0.27	1.52	6.31	1.05	93.20	7.57	41.71	382.51
	2015	-	216.14	20.20	0.28	1.56	6.46	1.08	95.41	7.75	42.70	391.57
	2016	-	220.62	20.62	0.29	1.59	6.59	1.10	97.38	7.91	43.58	399.68
	2017	-	225.17	21.04	0.29	1.62	6.72	1.12	99.39	8.08	44.48	407.93
	2018	-	229.79	21.48	0.30	1.65	6.86	1.15	101.43	8.24	45.39	416.29
	2019	-	234.48	21.91	0.30	1.69	7.00	1.17	103.50	8.41	46.32	424.79
	2020	-	239.24	22.36	0.31	1.72	7.14	1.19	105.60	8.58	47.26	433.42
	2021	-	244.08	22.81	0.32	1.76	7.29	1.22	107.74	8.76	48.22	442.17
	2022	-	248.98	23.27	0.32	1.79	7.44	1.24	109.90	8.93	49.19	451.06
	2023	-	253.96	23.73	0.33	1.83	7.58	1.27	112.10	9.11	50.17	460.09
	2024	-	259.02	24.21	0.34	1.86	7.74	1.29	114.33	9.29	51.17	469.25
	2025	-	264.15	24.69	0.34	1.90	7.89	1.32	116.60	9.48	52.18	478.54
Information & Cultural Industries	2004	-	10.25	12.52	0.34	-	4.00	0.29	25.91	-	19.86	73.16
	2005	-	9.37	11.44	0.31	-	3.66	0.27	23.68	-	18.15	66.88
	2006	-	9.65	11.79	0.32	-	3.77	0.28	24.40	-	18.71	68.92
	2007	-	9.94	12.15	0.33	-	3.88	0.28	25.13	-	19.26	70.98
	2008	-	10.24	12.51	0.34	-	4.00	0.29	25.90	-	19.85	73.13
	2009	-	10.59	12.94	0.35	-	4.13	0.30	26.77	-	20.52	75.60
	2010	-	10.84	13.25	0.36	-	4.23	0.31	27.41	-	21.01	77.41
	2011	-	11.15	13.63	0.37	-	4.35	0.32	28.19	-	21.61	79.62
	2012	-	11.47	14.01	0.38	-	4.48	0.33	28.99	-	22.22	81.88
	2013	-	11.79	14.41	0.39	-	4.61	0.34	29.82	-	22.86	84.22
	2014	-	12.12	14.81	0.40	-	4.73	0.35	30.65	-	23.49	86.56
	2015	-	12.51	15.28	0.42	-	4.88	0.36	31.62	-	24.24	89.30
	2016	-	12.87	15.72	0.43	-	5.02	0.37	32.53	-	24.93	91.87
	2017	-	13.23	16.17	0.44	-	5.17	0.38	33.46	-	25.65	94.49
	2018	-	13.61	16.63	0.45	-	5.31	0.39	34.41	-	26.38	97.19
	2019	-	14.00	17.10	0.47	-	5.47	0.40	35.39	-	27.13	99.95
	2020	-	14.39	17.59	0.48	-	5.62	0.41	36.39	-	27.89	102.78
	2021	-	14.80	18.08	0.49	-	5.78	0.42	37.42	-	28.68	105.68
	2022	-	15.22	18.59	0.51	-	5.94	0.43	38.47	-	29.49	108.64
	2023	-	15.64	19.11	0.52	-	6.11	0.45	39.55	-	30.31	111.69
	2024	-	16.08	19.65	0.53	-	6.28	0.46	40.65	-	31.16	114.80
	2025	-	16.52	20.19	0.55	-	6.45	0.47	41.78	-	32.02	117.99
Accommodation & Food Services	2004	-	1,050.70	19.25	1.21	10.57	6.41	1.02	103.47	117.73	196.12	1,506.47
	2005	-	1,088.52	19.94	1.25	10.95	6.64	1.05	107.19	121.97	203.18	1,560.70
	2006	-	1,111.23	20.36	1.28	11.18	6.78	1.08	109.43	124.51	207.41	1,593.26
	2007	-	1,133.67	20.77	1.31	11.41	6.92	1.10	111.64	127.03	211.60	1,625.43
	2008	-	1,156.99	21.20	1.33	11.64	7.06	1.12	113.93	129.64	215.95	1,658.86
	2009	-	1,184.79	21.71	1.36	11.92	7.23	1.15	116.67	132.75	221.14	1,698.73
	2010	-	1,201.60	22.02	1.38	12.09	7.33	1.16	118.33	134.64	224.28	1,722.83
	2011	-	1,224.35	22.43	1.41	12.32	7.47	1.19	120.57	137.19	228.53	1,755.44
	2012	-	1,247.21	22.85	1.44	12.55	7.61	1.21	122.82	139.75	232.79	1,788.22
	2013	-	1,270.76	23.28	1.46	12.78	7.75	1.23	125.14	142.39	237.19	1,821.99
	2014	-	1,293.69	23.70	1.49	13.02	7.89	1.25	127.39	144.96	241.47	1,854.87
	2015	-	1,322.14	24.22	1.52	13.30	8.07	1.28	130.20	148.14	246.78	1,895.65
	2016	-	1,347.29	24.69	1.55	13.55	8.22	1.30	132.67	150.96	251.47	1,931.71
	2017	-	1,372.77	25.15	1.58	13.81	8.37	1.33	135.18	153.82	256.23	1,968.25
	2018	-	1,398.60	25.63	1.61	14.07	8.53	1.35	137.72	156.71	261.05	2,005.28
	2019	-	1,424.76	26.10	1.64	14.33	8.69	1.38	140.30	159.64	265.94	2,042.79
	2020	-	1,451.27	26.59	1.67	14.60	8.85	1.41	142.91	162.61	270.88	2,080.80
	2021	-	1,478.12	27.08	1.70	14.87	9.02	1.43	145.56	165.62	275.90	2,119.30
	2022	-	1,505.32	27.58	1.73	15.14	9.18	1.46	148.23	168.67	280.97	2,158.30
	2023	-	1,532.88	28.09	1.76	15.42	9.35	1.48	150.95	171.76	286.12	2,197.80
	2024	-	1,560.78	28.60	1.80	15.70	9.52	1.51	153.70	174.88	291.32	2,237.82
	2025	-	1,589.05	29.11	1.83	15.99	9.69	1.54	156.48	178.05	296.60	2,278.34

Commercial Baseline Forecast (Peak MW)

	Years	Heat	Cool	Vent	Water	Cook	Refrig	Xlit	Ilit	Ofeq	Misc	Total
Health Care & Social Assistance	2004	-	262.17	38.61	0.36	2.36	12.08	1.48	115.76	21.70	73.15	527.66
	2005	-	253.83	37.38	0.34	2.29	11.69	1.43	112.08	21.01	70.82	510.86
	2006	-	259.67	38.24	0.35	2.34	11.96	1.46	114.66	21.49	72.45	522.62
	2007	-	265.47	39.10	0.36	2.39	12.23	1.50	117.22	21.97	74.07	534.30
	2008	-	271.50	39.98	0.37	2.44	12.51	1.53	119.88	22.47	75.75	546.44
	2009	-	278.62	41.03	0.38	2.51	12.84	1.57	123.02	23.06	77.73	560.76
	2010	-	283.17	41.70	0.38	2.55	13.04	1.60	125.03	23.44	79.00	569.92
	2011	-	289.14	42.58	0.39	2.60	13.32	1.63	127.67	23.93	80.67	581.93
	2012	-	295.16	43.47	0.40	2.66	13.60	1.66	130.33	24.43	82.35	594.05
	2013	-	301.37	44.38	0.41	2.71	13.88	1.70	133.07	24.94	84.08	606.55
	2014	-	307.46	45.28	0.42	2.77	14.16	1.73	135.76	25.45	85.78	618.80
	2015	-	314.88	46.37	0.43	2.84	14.51	1.78	139.03	26.06	87.85	633.74
	2016	-	321.55	47.35	0.44	2.90	14.81	1.81	141.98	26.61	89.71	647.16
	2017	-	328.32	48.35	0.44	2.96	15.12	1.85	144.97	27.17	91.60	660.80
	2018	-	335.21	49.37	0.45	3.02	15.44	1.89	148.01	27.74	93.52	674.65
	2019	-	342.20	50.40	0.46	3.08	15.76	1.93	151.10	28.32	95.47	688.72
	2020	-	349.30	51.44	0.47	3.15	16.09	1.97	154.23	28.91	97.46	703.02
	2021	-	356.52	52.50	0.48	3.21	16.42	2.01	157.42	29.51	99.47	717.54
	2022	-	363.84	53.58	0.49	3.28	16.76	2.05	160.65	30.11	101.51	732.29
	2023	-	371.29	54.68	0.50	3.34	17.10	2.09	163.94	30.73	103.59	747.27
	2024	-	378.85	55.79	0.51	3.41	17.45	2.14	167.28	31.35	105.70	762.48
	2025	-	386.52	56.92	0.52	3.48	17.81	2.18	170.67	31.99	107.84	777.93
Wholesale Trade	2004	-	302.64	26.93	0.17	2.41	9.90	0.85	81.60	15.04	66.94	506.50
	2005	-	293.72	26.14	0.16	2.34	9.61	0.83	79.20	14.60	64.97	491.58
	2006	-	295.79	26.33	0.16	2.36	9.68	0.83	79.76	14.70	65.42	495.04
	2007	-	297.68	26.49	0.16	2.37	9.74	0.84	80.27	14.80	65.84	498.20
	2008	-	299.69	26.67	0.16	2.39	9.81	0.84	80.81	14.90	66.29	501.56
	2009	-	302.74	26.94	0.17	2.41	9.91	0.85	81.63	15.05	66.96	506.67
	2010	-	302.88	26.96	0.17	2.42	9.91	0.85	81.67	15.06	66.99	506.90
	2011	-	304.44	27.09	0.17	2.43	9.96	0.86	82.09	15.13	67.34	509.51
	2012	-	305.93	27.23	0.17	2.44	10.01	0.86	82.49	15.21	67.67	512.00
	2013	-	307.48	27.37	0.17	2.45	10.06	0.87	82.91	15.28	68.01	514.60
	2014	-	308.80	27.48	0.17	2.46	10.11	0.87	83.26	15.35	68.30	516.80
	2015	-	311.32	27.71	0.17	2.48	10.19	0.88	83.94	15.47	68.86	521.02
	2016	-	312.94	27.85	0.17	2.50	10.24	0.88	84.38	15.56	69.22	523.74
	2017	-	314.55	27.99	0.17	2.51	10.29	0.89	84.81	15.64	69.57	526.43
	2018	-	316.13	28.14	0.17	2.52	10.35	0.89	85.24	15.71	69.92	529.07
	2019	-	317.68	28.27	0.17	2.53	10.40	0.89	85.66	15.79	70.27	531.67
	2020	-	319.22	28.41	0.18	2.55	10.45	0.90	86.07	15.87	70.61	534.24
	2021	-	320.72	28.54	0.18	2.56	10.50	0.90	86.48	15.94	70.94	536.76
	2022	-	322.20	28.68	0.18	2.57	10.54	0.91	86.88	16.02	71.27	539.24
	2023	-	323.66	28.81	0.18	2.58	10.59	0.91	87.27	16.09	71.59	541.68
	2024	-	325.09	28.93	0.18	2.59	10.64	0.92	87.66	16.16	71.91	544.07
	2025	-	326.50	29.06	0.18	2.60	10.68	0.92	88.04	16.23	72.22	546.43
Offices	2004	-	2,452.63	229.75	1.11	-	37.84	14.07	1,530.52	331.39	767.58	5,364.89
	2005	-	2,323.14	217.62	1.05	-	35.84	13.33	1,449.72	313.89	727.05	5,081.64
	2006	-	2,381.60	223.10	1.08	-	36.74	13.66	1,486.20	321.79	745.35	5,209.53
	2007	-	2,439.92	228.56	1.11	-	37.64	14.00	1,522.59	329.67	763.60	5,337.09
	2008	-	2,500.60	234.25	1.14	-	38.58	14.34	1,560.46	337.87	782.59	5,469.81
	2009	-	2,571.48	240.89	1.17	-	39.67	14.75	1,604.69	347.44	804.78	5,624.87
	2010	-	2,618.95	245.33	1.19	-	40.40	15.02	1,634.32	353.86	819.63	5,728.71
	2011	-	2,679.77	251.03	1.22	-	41.34	15.37	1,672.27	362.08	838.66	5,861.74
	2012	-	2,741.31	256.79	1.24	-	42.29	15.72	1,710.67	370.39	857.92	5,996.34
	2013	-	2,804.84	262.75	1.27	-	43.27	16.09	1,750.32	378.97	877.81	6,135.32
	2014	-	2,867.49	268.62	1.30	-	44.24	16.45	1,789.41	387.44	897.41	6,272.36
	2015	-	2,942.89	275.68	1.34	-	45.40	16.88	1,836.46	397.63	921.01	6,437.29
	2016	-	3,011.51	282.11	1.37	-	46.46	17.27	1,879.28	406.90	942.48	6,587.38
	2017	-	3,081.40	288.65	1.40	-	47.54	17.67	1,922.90	416.34	964.36	6,740.26
	2018	-	3,152.59	295.32	1.43	-	48.64	18.08	1,967.32	425.96	986.64	6,895.99
	2019	-	3,225.10	302.11	1.46	-	49.76	18.50	2,012.57	435.76	1,009.33	7,054.59
	2020	-	3,298.94	309.03	1.50	-	50.89	18.92	2,058.65	445.73	1,032.44	7,216.12
	2021	-	3,374.14	316.08	1.53	-	52.05	19.35	2,105.58	455.90	1,055.98	7,380.60
	2022	-	3,450.71	323.25	1.57	-	53.24	19.79	2,153.36	466.24	1,079.94	7,548.10
	2023	-	3,528.68	330.55	1.60	-	54.44	20.24	2,202.01	476.78	1,104.34	7,718.64
	2024	-	3,608.06	337.99	1.64	-	55.66	20.70	2,251.55	487.50	1,129.18	7,892.27
	2025	-	3,688.87	345.56	1.68	-	56.91	21.16	2,301.98	498.42	1,154.47	8,069.04
Retail Trade	2004	-	868.83	72.34	0.45	6.57	13.43	2.09	199.77	40.95	180.55	1,384.98
	2005	-	839.25	69.88	0.44	6.35	12.97	2.02	192.97	39.56	174.40	1,337.83
	2006	-	846.75	70.50	0.44	6.41	13.09	2.03	194.69	39.91	175.96	1,349.78
	2007	-	853.75	71.09	0.44	6.46	13.20	2.05	196.30	40.24	177.41	1,360.94
	2008	-	861.13	71.70	0.45	6.51	13.31	2.07	198.00	40.59	178.94	1,372.70
	2009	-	871.52	72.57	0.45	6.59	13.47	2.09	200.39	41.08	181.10	1,389.27
	2010	-	873.55	72.74	0.45	6.61	13.50	2.10	200.86	41.18	181.53	1,392.51
	2011	-	879.69	73.25	0.46	6.65	13.60	2.11	202.27	41.47	182.80	1,402.29
	2012	-	885.64	73.74	0.46	6.70	13.69	2.13	203.64	41.75	184.04	1,411.78
	2013	-	891.82	74.26	0.46	6.75	13.79	2.14	205.06	42.04	185.32	1,421.63
	2014	-	897.31	74.71	0.47	6.79	13.87	2.15	206.32	42.30	186.46	1,430.38
	2015	-	906.32	75.46	0.47	6.86	14.01	2.18	208.39	42.72	188.34	1,444.75
	2016	-	912.77	76.00	0.48	6.90	14.11	2.19	209.87	43.03	189.68	1,455.03
	2017	-	919.17	76.53	0.48	6.95	14.21	2.21	211.34	43.33	191.01	1,465.23
	2018	-	925.51	77.06	0.48	7.00	14.31	2.22	212.80	43.63	192.33	1,475.34
	2019	-	931.81	77.59	0.49	7.05	14.40	2.24	214.25	43.92	193.63	1,485.38
	2020	-	938.06	78.11	0.49	7.10	14.50	2.25	215.69	44.22	194.93	1,495.34
	2021	-	944.25	78.62	0.49	7.14	14.60	2.27	217.11	44.51	196.22	1,505.21
	2022	-	950.39	79.13	0.49	7.19	14.69	2.28	218.52	44.80	197.49	1,514.99
	2023	-	956.47	79.64	0.50	7.24	14.79	2.30	219.92	45.09	198.76	1,524.70
	2024	-	962.51	80.14	0.50	7.28	14.88	2.31	221.31	45.37	200.01	1,534.31
	2025	-	968.49	80.64	0.50	7.33	14.97	2.33	222.68	45.65	201.25	1,543.84

Commercial Baseline Forecast (Peak MW)

	Years	Heat	Cool	Vent	Water	Cook	Refrig	Xlit	Ilit	Ofeq	Misc	Total
Transportation & Warehousing	2004	-	95.07	20.68	0.16	-	-	0.68	111.26	-	40.42	268.28
	2005	-	82.27	17.90	0.14	-	-	0.59	96.27	-	34.98	232.14
	2006	-	82.49	17.94	0.14	-	-	0.59	96.53	-	35.07	232.76
	2007	-	82.65	17.98	0.14	-	-	0.59	96.72	-	35.14	233.22
	2008	-	82.85	18.02	0.14	-	-	0.59	96.95	-	35.22	233.78
	2009	-	83.32	18.13	0.14	-	-	0.59	97.51	-	35.43	235.13
	2010	-	83.00	18.06	0.14	-	-	0.59	97.13	-	35.29	234.21
	2011	-	83.06	18.07	0.14	-	-	0.59	97.20	-	35.32	234.39
	2012	-	83.10	18.08	0.14	-	-	0.59	97.25	-	35.33	234.51
	2013	-	83.16	18.09	0.14	-	-	0.59	97.32	-	35.36	234.67
	2014	-	83.15	18.09	0.14	-	-	0.59	97.31	-	35.36	234.65
	2015	-	83.47	18.16	0.14	-	-	0.59	97.68	-	35.49	235.53
	2016	-	83.54	18.17	0.14	-	-	0.59	97.76	-	35.52	235.73
	2017	-	83.60	18.19	0.14	-	-	0.59	97.83	-	35.55	235.91
	2018	-	83.66	18.20	0.15	-	-	0.60	97.90	-	35.57	236.06
	2019	-	83.70	18.21	0.15	-	-	0.60	97.95	-	35.59	236.19
	2020	-	83.74	18.22	0.15	-	-	0.60	97.99	-	35.60	236.29
	2021	-	83.77	18.22	0.15	-	-	0.60	98.03	-	35.62	236.37
	2022	-	83.79	18.23	0.15	-	-	0.60	98.05	-	35.62	236.43
	2023	-	83.80	18.23	0.15	-	-	0.60	98.07	-	35.63	236.47
	2024	-	83.80	18.23	0.15	-	-	0.60	98.07	-	35.63	236.48
	2025	-	83.80	18.23	0.15	-	-	0.60	98.07	-	35.63	236.47
Other Services	2004	-	75.88	5.22	0.05	-	1.06	0.23	22.00	-	9.85	114.29
	2005	-	70.57	4.85	0.05	-	0.99	0.21	20.46	-	9.16	106.29
	2006	-	71.59	4.92	0.05	-	1.00	0.22	20.76	-	9.29	107.82
	2007	-	72.57	4.99	0.05	-	1.02	0.22	21.04	-	9.42	109.31
	2008	-	73.60	5.06	0.05	-	1.03	0.22	21.34	-	9.55	110.85
	2009	-	74.89	5.15	0.05	-	1.05	0.22	21.71	-	9.72	112.80
	2010	-	75.47	5.19	0.05	-	1.06	0.23	21.88	-	9.80	113.68
	2011	-	76.42	5.25	0.05	-	1.07	0.23	22.16	-	9.92	115.10
	2012	-	77.35	5.32	0.05	-	1.08	0.23	22.43	-	10.04	116.51
	2013	-	78.32	5.38	0.05	-	1.10	0.24	22.71	-	10.16	117.96
	2014	-	79.23	5.45	0.05	-	1.11	0.24	22.97	-	10.28	119.33
	2015	-	80.46	5.53	0.05	-	1.13	0.24	23.33	-	10.44	121.18
	2016	-	81.47	5.60	0.05	-	1.14	0.24	23.62	-	10.57	122.71
	2017	-	82.49	5.67	0.05	-	1.16	0.25	23.92	-	10.71	124.24
	2018	-	83.51	5.74	0.05	-	1.17	0.25	24.21	-	10.84	125.78
	2019	-	84.53	5.81	0.05	-	1.18	0.25	24.51	-	10.97	127.32
	2020	-	85.56	5.88	0.05	-	1.20	0.26	24.81	-	11.10	128.87
	2021	-	86.60	5.95	0.06	-	1.21	0.26	25.11	-	11.24	130.43
	2022	-	87.63	6.03	0.06	-	1.23	0.26	25.41	-	11.37	131.99
	2023	-	88.68	6.10	0.06	-	1.24	0.27	25.71	-	11.51	133.56
	2024	-	89.72	6.17	0.06	-	1.26	0.27	26.01	-	11.64	135.13
	2025	-	90.77	6.24	0.06	-	1.27	0.27	26.32	-	11.78	136.71

Industrial Baseline Forecast (MWh)

	Years	HVAC	Process Heat & Boiler Fuel	Process Cooling	Process Machine Drive	Electrochemical Process	Other Process	Xlit	Ilit	Other	Total
Iron and Steel	2004	186,474	1,838,253	42,826	1,546,731	2,118,417	16,640	31,185	144,007	98,557	6,023,091
	2005	240,831	2,374,103	55,310	1,997,603	2,735,935	21,491	40,167	186,093	127,287	7,778,820
	2006	243,333	2,398,770	55,885	2,018,358	2,764,361	21,714	40,625	187,986	128,609	7,859,642
	2007	245,862	2,423,693	56,466	2,039,329	2,793,083	21,940	41,113	189,873	129,946	7,941,304
	2008	248,416	2,448,875	57,052	2,060,518	2,822,103	22,167	41,543	191,844	131,296	8,023,814
	2009	250,997	2,474,319	57,645	2,081,926	2,851,424	22,398	41,869	193,942	132,660	8,107,181
	2010	253,605	2,500,027	58,244	2,103,558	2,881,051	22,630	42,104	196,158	134,038	8,191,415
	2011	256,240	2,526,003	58,849	2,125,414	2,910,985	22,866	42,306	198,431	135,431	8,276,524
	2012	258,902	2,552,248	59,461	2,147,497	2,941,230	23,103	42,549	200,689	136,838	8,362,517
	2013	261,592	2,578,766	60,078	2,169,809	2,971,789	23,343	42,884	202,882	138,260	8,449,403
	2014	264,310	2,605,559	60,703	2,192,353	3,002,666	23,586	43,333	204,986	139,696	8,537,193
	2015	267,057	2,632,631	61,333	2,215,132	3,033,864	23,831	43,867	207,032	141,148	8,625,894
	2016	269,831	2,659,984	61,971	2,238,147	3,065,386	24,078	44,409	209,097	142,614	8,715,517
	2017	272,635	2,687,621	62,614	2,261,401	3,097,235	24,329	44,871	211,269	144,096	8,806,071
	2018	275,467	2,715,545	63,265	2,284,897	3,129,415	24,581	45,221	213,580	145,593	8,897,566
	2019	278,330	2,743,760	63,922	2,308,638	3,161,930	24,837	45,494	215,996	147,106	8,990,012
	2020	281,221	2,772,268	64,586	2,332,624	3,194,783	25,095	45,748	218,459	148,634	9,083,418
	2021	284,143	2,801,071	65,258	2,356,860	3,227,976	25,356	46,103	220,849	150,179	9,177,795
	2022	287,096	2,830,175	65,936	2,381,348	3,261,515	25,619	46,562	223,163	151,739	9,273,152
	2023	290,079	2,859,580	66,621	2,406,090	3,295,402	25,885	47,139	225,389	153,315	9,369,500
	2024	293,092	2,889,291	67,313	2,431,090	3,329,641	26,154	47,820	227,539	154,908	9,466,849
	2025	296,138	2,919,311	68,012	2,456,349	3,364,236	26,426	48,317	229,903	156,518	9,565,210
Pulp & Paper	2004	449,837	302,105	130,941	7,251,775	52,001	15,913	68,743	317,440	228,051	8,816,807
	2005	478,063	321,061	139,157	7,706,795	55,264	16,912	72,859	337,555	242,360	9,370,026
	2006	483,030	324,397	140,603	7,786,868	55,838	17,088	73,691	340,988	244,879	9,467,381
	2007	488,048	327,767	142,064	7,867,774	56,418	17,265	74,576	344,412	247,423	9,565,747
	2008	493,119	331,173	143,540	7,949,520	57,004	17,445	75,354	347,986	249,994	9,665,135
	2009	498,243	334,614	145,032	8,032,116	57,596	17,626	75,947	351,792	252,591	9,765,556
	2010	503,419	338,090	146,539	8,115,569	58,195	17,809	76,372	355,811	255,215	9,867,020
	2011	508,650	341,603	148,061	8,199,890	58,799	17,994	76,740	359,934	257,867	9,969,538
	2012	513,935	345,152	149,599	8,285,087	59,410	18,181	77,180	364,031	260,546	10,073,122
	2013	519,275	348,738	151,154	8,371,169	60,028	18,370	77,787	368,008	263,253	10,177,782
	2014	524,670	352,362	152,724	8,458,145	60,651	18,561	78,601	371,825	265,989	10,283,529
	2015	530,121	356,023	154,311	8,546,026	61,281	18,754	79,570	375,537	268,752	10,390,375
	2016	535,629	359,722	155,914	8,634,819	61,918	18,948	80,554	379,281	271,545	10,498,331
	2017	541,194	363,459	157,534	8,724,535	62,561	19,145	81,392	383,221	274,366	10,607,408
	2018	546,817	367,236	159,171	8,815,182	63,211	19,344	82,027	387,413	277,217	10,717,619
	2019	552,499	371,051	160,825	8,906,772	63,868	19,545	82,522	391,796	280,097	10,828,975
	2020	558,239	374,907	162,496	8,999,314	64,532	19,748	82,983	396,263	283,007	10,941,488
	2021	564,039	378,802	164,184	9,092,816	65,202	19,953	83,626	400,599	285,948	11,055,171
	2022	569,900	382,738	165,890	9,187,291	65,880	20,161	84,460	404,797	288,919	11,170,034
	2023	575,821	386,714	167,614	9,282,747	66,564	20,370	85,506	408,833	291,920	11,286,090
	2024	581,804	390,732	169,355	9,379,195	67,256	20,582	86,742	412,734	294,953	11,403,353
	2025	587,849	394,792	171,115	9,476,644	67,955	20,796	87,643	417,023	298,018	11,521,834
Petroleum Refining	2004	53,774	27,412	76,384	1,515,467	350	-	8,521	39,350	15,757	1,737,014
	2005	57,782	29,455	82,077	1,628,431	376	-	9,132	42,308	16,931	1,866,492
	2006	58,382	29,761	82,930	1,645,350	380	-	9,236	42,738	17,107	1,885,885
	2007	58,989	30,071	83,792	1,662,445	384	-	9,347	43,167	17,285	1,905,480
	2008	59,602	30,383	84,662	1,679,718	388	-	9,445	43,615	17,465	1,925,277
	2009	60,221	30,699	85,542	1,697,170	392	-	9,519	44,092	17,646	1,945,281
	2010	60,847	31,018	86,431	1,714,804	396	-	9,572	44,596	17,830	1,965,493
	2011	61,479	31,340	87,329	1,732,621	400	-	9,618	45,112	18,015	1,985,914
	2012	62,118	31,666	88,236	1,750,623	404	-	9,673	45,626	18,202	2,006,548
	2013	62,763	31,995	89,153	1,768,812	409	-	9,749	46,124	18,391	2,027,396
	2014	63,415	32,327	90,079	1,787,190	413	-	9,852	46,603	18,582	2,048,460
	2015	64,074	32,663	91,015	1,805,758	417	-	9,973	47,068	18,775	2,069,744
	2016	64,740	33,002	91,961	1,824,520	422	-	10,096	47,537	18,970	2,091,249
	2017	65,413	33,345	92,916	1,843,477	426	-	10,201	48,031	19,167	2,112,977
	2018	66,092	33,692	93,882	1,862,631	430	-	10,281	48,557	19,367	2,134,930
	2019	66,779	34,042	94,857	1,881,983	435	-	10,343	49,106	19,568	2,157,112
	2020	67,473	34,395	95,843	1,901,537	439	-	10,401	49,666	19,771	2,179,525
	2021	68,174	34,753	96,838	1,921,294	444	-	10,481	50,209	19,976	2,202,170
	2022	68,882	35,114	97,845	1,941,256	449	-	10,586	50,735	20,184	2,225,051
	2023	69,598	35,479	98,861	1,961,426	453	-	10,717	51,241	20,394	2,248,169
	2024	70,321	35,847	99,888	1,981,805	458	-	10,872	51,730	20,606	2,271,527
	2025	71,051	36,220	100,926	2,002,396	463	-	10,985	52,268	20,820	2,295,128
Smelting and Refining	2004	69,474	684,876	15,956	576,264	789,257	6,200	11,619	53,652	36,719	2,244,018
	2005	88,060	868,092	20,224	730,425	1,000,396	7,858	14,687	68,045	46,542	2,844,329
	2006	88,975	877,111	20,434	738,014	1,010,790	7,940	14,855	68,737	47,026	2,873,882
	2007	89,899	886,225	20,647	745,682	1,021,292	8,022	15,033	69,427	47,515	2,903,742
	2008	90,834	895,432	20,861	753,429	1,031,903	8,106	15,190	70,148	48,008	2,933,911
	2009	91,777	904,736	21,078	761,257	1,042,625	8,190	15,310	70,915	48,507	2,964,395
	2010	92,731	914,136	21,297	769,167	1,053,458	8,275	15,395	71,725	49,011	2,995,195
	2011	93,694	923,634	21,518	777,158	1,064,403	8,361	15,469	72,556	49,520	3,026,315
	2012	94,668	933,231	21,742	785,233	1,075,462	8,448	15,558	73,382	50,035	3,057,758
	2013	95,651	942,927	21,968	793,392	1,086,636	8,535	15,681	74,184	50,555	3,089,528
	2014	96,645	952,724	22,196	801,635	1,097,926	8,624	15,845	74,953	51,080	3,121,629
	2015	97,649	962,623	22,427	809,964	1,109,334	8,714	16,040	75,701	51,611	3,154,062
	2016	98,664	972,624	22,660	818,380	1,120,860	8,804	16,238	76,456	52,147	3,186,833
	2017	99,689	982,730	22,895	826,883	1,132,506	8,896	16,407	77,251	52,689	3,219,944
	2018	100,725	992,940	23,133	835,474	1,144,272	8,988	16,535	78,096	53,236	3,253,399
	2019	101,771	1,003,257	23,373	844,154	1,156,161	9,082	16,635	78,979	53,789	3,287,202
	2020	102,829	1,013,681	23,616	852,925	1,168,174	9,176	16,728	79,880	54,348	3,321,356
	2021	103,897	1,024,213	23,861	861,787	1,180,311	9,271	16,858	80,754	54,913	3,355,865
	2022	104,977	1,034,855	24,109	870,741	1,192,575	9,368	17,026	81,600	55,483	3,390,733
	2023	106,067	1,045,607	24,360	879,788	1,204,965	9,465	17,237	82,414	56,060	3,425,962
	2024	107,169	1,056,471	24,613	888,929	1,217,485	9,563	17,486	83,200	56,642	3,461,558
	2025	108,283	1,067,447	24,869	898,165	1,230,135	9,663	17,667	84,064	57,231	3,497,524

Industrial Baseline Forecast (MWh)

	Years	HVAC	Process Heat & Boiler Fuel	Process Cooling	Process Machine Drive	Electrochemical Process	Other Process	Xlit	Iiit	Other	Total
Cement	2004	23,200	98,479	13,040	730,796	-	7,920	4,229	19,530	11,760	908,955
	2005	23,831	101,158	13,395	750,672	-	8,135	4,333	20,073	12,080	933,676
	2006	24,078	102,209	13,534	758,471	-	8,220	4,382	20,278	12,205	943,377
	2007	24,329	103,271	13,674	766,352	-	8,305	4,435	20,481	12,332	953,179
	2008	24,581	104,344	13,816	774,314	-	8,392	4,481	20,694	12,460	963,082
	2009	24,837	105,428	13,960	782,359	-	8,479	4,516	20,920	12,590	973,089
	2010	25,095	106,523	14,105	790,488	-	8,567	4,542	21,159	12,720	983,199
	2011	25,356	107,630	14,252	798,701	-	8,656	4,563	21,404	12,853	993,415
	2012	25,619	108,748	14,400	807,000	-	8,746	4,590	21,648	12,986	1,003,736
	2013	25,885	109,878	14,549	815,384	-	8,837	4,626	21,884	13,121	1,014,165
	2014	26,154	111,020	14,700	823,856	-	8,928	4,674	22,111	13,257	1,024,702
	2015	26,426	112,173	14,853	832,416	-	9,021	4,732	22,332	13,395	1,035,349
	2016	26,700	113,339	15,008	841,065	-	9,115	4,790	22,555	13,534	1,046,106
	2017	26,978	114,517	15,163	849,804	-	9,210	4,840	22,789	13,675	1,056,975
	2018	27,258	115,706	15,321	858,633	-	9,305	4,878	23,038	13,817	1,067,957
	2019	27,541	116,909	15,480	867,554	-	9,402	4,907	23,299	13,961	1,079,053
	2020	27,828	118,123	15,641	876,568	-	9,500	4,935	23,565	14,106	1,090,265
	2021	28,117	119,350	15,804	885,676	-	9,598	4,973	23,822	14,252	1,101,592
	2022	28,409	120,591	15,968	894,878	-	9,698	5,023	24,072	14,400	1,113,038
	2023	28,704	121,843	16,134	904,176	-	9,799	5,085	24,312	14,550	1,124,603
	2024	29,002	123,109	16,301	913,570	-	9,901	5,158	24,544	14,701	1,136,287
	2025	29,304	124,389	16,471	923,062	-	10,004	5,212	24,799	14,854	1,148,093
Misc Manufacturing	2004	4,588,226	1,555,502	809,316	4,458,180	58,079	-	336,898	1,555,714	1,550,452	14,912,367
	2005	5,048,185	1,711,438	890,448	4,905,102	63,901	-	369,671	1,712,671	1,705,881	16,407,296
	2006	5,100,636	1,729,219	899,699	4,956,066	64,565	-	373,888	1,730,089	1,723,605	16,577,768
	2007	5,153,631	1,747,186	909,047	5,007,560	65,236	-	378,378	1,747,459	1,741,513	16,750,011
	2008	5,207,178	1,765,339	918,492	5,059,588	65,914	-	382,330	1,765,595	1,759,608	16,924,044
	2009	5,261,280	1,783,681	928,035	5,112,157	66,598	-	385,337	1,784,905	1,777,890	17,099,884
	2010	5,315,945	1,802,214	937,678	5,165,273	67,290	-	387,494	1,805,297	1,796,362	17,277,552
	2011	5,371,178	1,820,939	947,420	5,218,940	67,990	-	389,357	1,826,216	1,815,026	17,457,066
	2012	5,426,984	1,839,858	957,264	5,273,165	68,696	-	391,593	1,847,001	1,833,885	17,638,445
	2013	5,483,370	1,858,974	967,210	5,327,953	69,410	-	394,673	1,867,180	1,852,939	17,821,708
	2014	5,540,343	1,878,289	977,259	5,383,310	70,131	-	398,804	1,886,549	1,872,191	18,006,876
	2015	5,597,907	1,897,804	987,413	5,439,243	70,860	-	403,719	1,905,379	1,891,643	18,193,967
	2016	5,656,069	1,917,523	997,672	5,495,757	71,596	-	408,712	1,924,378	1,911,297	18,383,003
	2017	5,714,836	1,937,446	1,008,038	5,552,858	72,340	-	412,961	1,944,369	1,931,155	18,574,002
	2018	5,774,213	1,957,576	1,018,511	5,610,552	73,091	-	416,185	1,965,638	1,951,220	18,766,986
	2019	5,834,207	1,977,915	1,029,094	5,668,845	73,851	-	418,696	1,987,874	1,971,493	18,961,975
	2020	5,894,824	1,998,465	1,039,786	5,727,745	74,618	-	421,035	2,010,539	1,991,977	19,158,990
	2021	5,956,071	2,019,230	1,050,589	5,787,256	75,393	-	424,297	2,032,541	2,012,674	19,358,052
	2022	6,017,955	2,040,209	1,061,505	5,847,386	76,177	-	428,528	2,053,837	2,033,585	19,559,182
	2023	6,080,482	2,061,407	1,072,534	5,908,140	76,968	-	433,838	2,074,319	2,054,714	19,762,402
	2024	6,143,658	2,082,825	1,083,678	5,969,526	77,768	-	440,106	2,094,111	2,076,063	19,967,733
	2025	6,207,490	2,104,466	1,094,937	6,031,549	78,576	-	444,678	2,115,869	2,097,633	20,175,198
Chemicals	2004	241,148	132,746	290,469	2,574,441	620,042	3,811	30,586	141,239	73,230	4,107,712
	2005	264,989	145,870	319,186	2,828,963	681,342	4,188	33,519	155,293	80,470	4,513,820
	2006	267,742	147,386	322,503	2,858,356	688,421	4,231	33,902	156,873	81,306	4,560,719
	2007	270,524	148,917	325,854	2,888,054	695,574	4,275	34,309	158,448	82,151	4,608,105
	2008	273,334	150,465	329,239	2,918,061	702,801	4,319	34,667	160,092	83,004	4,655,983
	2009	276,174	152,028	332,660	2,948,379	710,103	4,364	34,940	161,843	83,867	4,704,359
	2010	279,044	153,607	336,116	2,979,013	717,481	4,410	35,135	163,692	84,738	4,753,237
	2011	281,943	155,203	339,609	3,009,965	724,935	4,455	35,304	165,589	85,619	4,802,623
	2012	284,872	156,816	343,137	3,041,239	732,468	4,502	35,507	167,474	86,508	4,852,522
	2013	287,832	158,445	346,702	3,072,837	740,078	4,549	35,786	169,303	87,407	4,902,940
	2014	290,823	160,092	350,305	3,104,764	747,767	4,596	36,161	171,060	88,315	4,953,882
	2015	293,844	161,755	353,944	3,137,022	755,537	4,644	36,607	172,767	89,233	5,005,352
	2016	296,897	163,436	357,622	3,169,616	763,387	4,692	37,059	174,490	90,160	5,057,358
	2017	299,982	165,134	361,337	3,202,548	771,318	4,741	37,445	176,302	91,097	5,109,904
	2018	303,099	166,849	365,092	3,235,823	779,332	4,790	37,737	178,231	92,043	5,162,996
	2019	306,248	168,583	368,885	3,269,443	787,429	4,840	37,965	180,247	93,000	5,216,639
	2020	309,430	170,335	372,718	3,303,412	795,611	4,890	38,177	182,302	93,966	5,270,840
	2021	312,645	172,104	376,590	3,337,735	803,877	4,941	38,472	184,297	94,942	5,325,604
	2022	315,894	173,892	380,503	3,372,414	812,230	4,992	38,856	186,228	95,929	5,380,937
	2023	319,176	175,699	384,456	3,407,453	820,669	5,044	39,338	188,085	96,925	5,436,845
	2024	322,492	177,525	388,451	3,442,857	829,195	5,096	39,906	189,880	97,932	5,493,334
	2025	325,843	179,369	392,487	3,478,628	837,811	5,149	40,320	191,853	98,950	5,550,410
Mining	2004	277,736	381,026	190,651	1,600,667	305,193	11,830	38,605	178,270	129,108	3,113,086
	2005	279,112	382,913	191,595	1,608,594	306,704	11,888	38,692	179,258	129,748	3,128,504
	2006	282,011	386,891	193,586	1,625,307	309,891	12,012	39,133	181,081	131,096	3,161,009
	2007	284,942	390,911	195,597	1,642,194	313,111	12,137	39,603	182,899	132,458	3,193,852
	2008	287,902	394,972	197,630	1,659,257	316,364	12,263	40,017	184,797	133,834	3,227,036
	2009	290,893	399,076	199,683	1,676,496	319,651	12,390	40,332	186,819	135,225	3,260,565
	2010	293,916	403,223	201,758	1,693,915	322,972	12,519	40,557	188,953	136,630	3,294,442
	2011	296,970	407,412	203,854	1,711,515	326,328	12,649	40,752	191,142	138,049	3,328,671
	2012	300,055	411,645	205,972	1,729,297	329,718	12,780	40,986	193,318	139,484	3,363,256
	2013	303,173	415,922	208,112	1,747,265	333,144	12,913	41,309	195,430	140,933	3,398,201
	2014	306,323	420,244	210,274	1,765,419	336,606	13,047	41,741	197,457	142,397	3,433,508
	2015	309,505	424,610	212,459	1,783,762	340,103	13,183	42,256	199,428	143,877	3,469,182
	2016	312,721	429,022	214,666	1,802,295	343,637	13,320	42,778	201,417	145,372	3,505,227
	2017	315,970	433,479	216,897	1,821,021	347,207	13,458	43,223	203,509	146,882	3,541,646
	2018	319,253	437,983	219,150	1,839,941	350,814	13,598	43,560	205,735	148,408	3,578,444
	2019	322,570	442,534	221,427	1,859,058	354,459	13,739	43,823	208,062	149,950	3,615,624
	2020	325,922	447,132	223,728	1,878,374	358,142	13,882	44,068	210,435	151,508	3,653,190
	2021	329,308	451,777	226,053	1,897,890	361,863	14,026	44,409	212,738	153,082	3,691,147
	2022	332,730	456,471	228,401	1,917,609	365,623	14,172	44,852	214,967	154,673	3,729,498
	2023	336,187	461,214	230,774	1,937,533	369,422	14,319	45,408	217,110	156,280	3,768,247
	2024	339,680	466,006	233,172	1,957,664	373,260	14,468	46,064	219,182	157,904	3,807,399
	2025	343,209	470,848	235,595	1,978,004	377,138	14,618	46,543	221,459	159,544	3,846,958

Industrial Baseline Forecast (Peak MW)

	Years	HVAC	Process Heat & Boiler Fuel	Process Cooling	Process Machine Drive	Electrochemical Process	Other Process	Xlit	Ilit	Other	Total
Iron and Steel	2004	30	297	7	250	342	3	0	23	16	969
	2005	36	357	8	301	412	3	0	28	19	1,165
	2006	37	363	8	305	418	3	0	28	19	1,183
	2007	37	368	9	310	424	3	0	29	20	1,201
	2008	38	374	9	314	431	3	1	29	20	1,219
	2009	39	381	9	320	439	3	1	30	20	1,241
	2010	39	384	9	323	442	3	1	30	21	1,252
	2011	39	389	9	327	448	4	1	31	21	1,269
	2012	40	394	9	332	454	4	1	31	21	1,285
	2013	41	399	9	336	460	4	1	31	21	1,303
	2014	41	404	9	340	466	4	1	32	22	1,319
	2015	42	411	10	346	474	4	1	32	22	1,341
	2016	42	417	10	351	480	4	1	33	22	1,359
	2017	43	422	10	355	487	4	1	33	23	1,377
	2018	43	428	10	360	493	4	1	34	23	1,395
	2019	44	434	10	365	500	4	1	34	23	1,414
	2020	45	439	10	370	506	4	1	35	24	1,432
	2021	45	445	10	374	513	4	1	35	24	1,451
	2022	46	451	10	379	519	4	1	36	24	1,470
	2023	46	456	11	384	526	4	1	36	24	1,489
	2024	47	462	11	389	533	4	1	36	25	1,508
	2025	47	468	11	394	539	4	1	37	25	
Pulp & Paper	2004	67	45	20	1,083	8	2	1	47	34	1,307
	2005	66	45	19	1,072	8	2	1	47	34	1,294
	2006	67	45	20	1,088	8	2	1	48	34	1,314
	2007	68	46	20	1,104	8	2	1	48	35	1,333
	2008	70	47	20	1,121	8	2	1	49	35	1,353
	2009	71	48	21	1,141	8	3	1	50	36	1,378
	2010	71	48	21	1,151	8	3	1	50	36	1,390
	2011	72	49	21	1,167	8	3	1	51	37	1,408
	2012	73	49	21	1,182	8	3	1	52	37	1,427
	2013	74	50	22	1,198	9	3	1	53	38	1,446
	2014	75	51	22	1,213	9	3	1	53	38	1,464
	2015	76	51	22	1,233	9	3	1	54	39	1,488
	2016	78	52	23	1,249	9	3	1	55	39	1,508
	2017	79	53	23	1,266	9	3	1	56	40	1,529
	2018	80	53	23	1,283	9	3	1	56	40	1,549
	2019	81	54	23	1,300	9	3	1	57	41	1,569
	2020	82	55	24	1,317	9	3	1	58	41	1,590
	2021	83	56	24	1,334	10	3	1	59	42	1,611
	2022	84	56	24	1,351	10	3	1	60	42	1,632
	2023	85	57	25	1,369	10	3	1	60	43	1,653
	2024	86	58	25	1,386	10	3	1	61	44	1,674
	2025	87	58	25	1,404	10	3	1	62	44	
Petroleum Refining	2004	10	5	15	294	0	-	0	8	3	335
	2005	10	5	15	294	0	-	0	8	3	335
	2006	11	5	15	298	0	-	0	8	3	340
	2007	11	5	15	303	0	-	0	8	3	345
	2008	11	6	15	307	0	-	0	8	3	351
	2009	11	6	16	313	0	-	0	8	3	357
	2010	11	6	16	316	0	-	0	8	3	360
	2011	11	6	16	320	0	-	0	8	3	365
	2012	11	6	16	324	0	-	0	8	3	370
	2013	12	6	17	328	0	-	0	9	3	375
	2014	12	6	17	332	0	-	0	9	3	379
	2015	12	6	17	338	0	-	0	9	4	386
	2016	12	6	17	343	0	-	0	9	4	391
	2017	12	6	17	347	0	-	0	9	4	396
	2018	12	6	18	352	0	-	0	9	4	401
	2019	13	6	18	356	0	-	0	9	4	407
	2020	13	7	18	361	0	-	0	9	4	412
	2021	13	7	18	366	0	-	0	10	4	417
	2022	13	7	19	370	0	-	0	10	4	423
	2023	13	7	19	375	0	-	0	10	4	428
	2024	13	7	19	380	0	-	0	10	4	434
	2025	14	7	19	385	0	-	0	10	4	
Smelting and Refining	2004	11	111	3	93	128	1	0	9	6	361
	2005	13	131	3	110	151	1	0	10	7	426
	2006	13	133	3	112	153	1	0	10	7	433
	2007	14	135	3	113	155	1	0	11	7	439
	2008	14	137	3	115	157	1	0	11	7	446
	2009	14	139	3	117	160	1	0	11	7	454
	2010	14	140	3	118	162	1	0	11	8	458
	2011	14	142	3	120	164	1	0	11	8	464
	2012	15	144	3	121	166	1	0	11	8	470
	2013	15	146	3	123	168	1	0	11	8	476
	2014	15	148	3	124	170	1	0	12	8	482
	2015	15	150	4	126	173	1	0	12	8	490
	2016	15	152	4	128	176	1	0	12	8	497
	2017	16	154	4	130	178	1	0	12	8	504
	2018	16	156	4	132	180	1	0	12	8	510
	2019	16	159	4	133	183	1	0	12	8	517
	2020	16	161	4	135	185	1	0	13	9	524
	2021	17	163	4	137	187	1	0	13	9	531
	2022	17	165	4	139	190	1	0	13	9	537
	2023	17	167	4	140	192	2	0	13	9	544
	2024	17	169	4	142	195	2	0	13	9	551
	2025	17	171	4	144	197	2	0	13	9	

	Years	HVAC	Process Heat & Boiler Fuel	Process Cooling	Process Machine Drive	Electrochemical Process	Other Process	Xlit	Ilit	Other	Total
Cement	2004	4	19	3	142	-	2	0	4	2	175
	2005	4	18	2	135	-	1	0	4	2	168
	2006	4	19	2	137	-	1	0	4	2	170
	2007	4	19	2	140	-	2	0	4	2	173
	2008	4	19	3	142	-	2	0	4	2	175
	2009	5	19	3	144	-	2	0	4	2	179
	2010	5	20	3	145	-	2	0	4	2	180
	2011	5	20	3	147	-	2	0	4	2	183
	2012	5	20	3	149	-	2	0	4	2	185
	2013	5	20	3	151	-	2	0	4	2	187
	2014	5	21	3	153	-	2	0	4	2	190
	2015	5	21	3	156	-	2	0	4	3	193
	2016	5	21	3	158	-	2	0	4	3	196
	2017	5	22	3	160	-	2	0	4	3	198
	2018	5	22	3	162	-	2	0	4	3	201
	2019	5	22	3	164	-	2	0	4	3	203
	2020	5	22	3	166	-	2	0	4	3	206
	2021	5	23	3	169	-	2	0	5	3	209
	2022	5	23	3	171	-	2	0	5	3	211
	2023	5	23	3	173	-	2	0	5	3	214
	2024	6	24	3	175	-	2	0	5	3	217
	2025	6	24	3	177	-	2	0	5	3	
Misc Manufacturing	2004	889	301	157	864	11	-	4	301	300	2,828
	2005	911	309	161	885	12	-	4	309	308	2,898
	2006	925	313	163	898	12	-	5	314	312	2,942
	2007	938	318	165	912	12	-	5	318	317	2,985
	2008	952	323	168	925	12	-	5	323	322	3,030
	2009	970	329	171	942	12	-	5	329	328	3,086
	2010	978	332	173	951	12	-	5	332	331	3,113
	2011	991	336	175	963	13	-	5	337	335	3,155
	2012	1,004	341	177	976	13	-	5	342	339	3,197
	2013	1,018	345	180	989	13	-	5	347	344	3,240
	2014	1,031	349	182	1,001	13	-	5	351	348	3,280
	2015	1,048	355	185	1,018	13	-	5	357	354	3,334
	2016	1,062	360	187	1,032	13	-	5	361	359	3,379
	2017	1,076	365	190	1,046	14	-	5	366	364	3,425
	2018	1,090	370	192	1,059	14	-	5	371	368	3,470
	2019	1,105	375	195	1,073	14	-	5	376	373	3,516
	2020	1,119	379	197	1,087	14	-	5	382	378	3,563
	2021	1,134	384	200	1,102	14	-	5	387	383	3,609
	2022	1,148	389	203	1,116	15	-	5	392	388	3,656
	2023	1,163	394	205	1,130	15	-	6	397	393	3,703
	2024	1,178	399	208	1,145	15	-	6	402	398	3,750
	2025	1,193	404	210	1,159	15	-	6	407	403	
Chemicals	2004	47	26	56	499	120	1	0	27	14	790
	2005	48	26	58	510	123	1	0	28	15	809
	2006	49	27	58	518	125	1	0	28	15	821
	2007	49	27	59	526	127	1	0	29	15	833
	2008	50	28	60	534	129	1	0	29	15	846
	2009	51	28	61	544	131	1	0	30	15	861
	2010	51	28	62	548	132	1	0	30	16	869
	2011	52	29	63	556	134	1	0	31	16	880
	2012	53	29	64	563	136	1	0	31	16	892
	2013	53	29	64	570	137	1	0	31	16	904
	2014	54	30	65	578	139	1	0	32	16	915
	2015	55	30	66	587	141	1	0	32	17	930
	2016	56	31	67	595	143	1	0	33	17	943
	2017	56	31	68	603	145	1	0	33	17	956
	2018	57	32	69	611	147	1	0	34	17	968
	2019	58	32	70	619	149	1	0	34	18	981
	2020	59	32	71	627	151	1	0	35	18	994
	2021	60	33	72	635	153	1	0	35	18	1,007
	2022	60	33	73	644	155	1	0	36	18	1,020
	2023	61	34	74	652	157	1	1	36	19	1,033
	2024	62	34	74	660	159	1	1	36	19	1,046
	2025	63	34	75	668	161	1	1	37	19	
Mining	2004	54	74	37	310	59	2	0	35	25	596
	2005	50	69	35	290	55	2	0	32	23	558
	2006	51	70	35	295	56	2	0	33	24	566
	2007	52	71	36	299	57	2	0	33	24	575
	2008	53	72	36	303	58	2	0	34	24	583
	2009	54	74	37	309	59	2	0	34	25	594
	2010	54	74	37	312	59	2	0	35	25	599
	2011	55	75	38	316	60	2	1	35	25	607
	2012	56	76	38	320	61	2	1	36	26	615
	2013	56	77	39	324	62	2	1	36	26	624
	2014	57	78	39	328	63	2	1	37	26	631
	2015	58	79	40	334	64	2	1	37	27	642
	2016	59	81	40	338	65	3	1	38	27	651
	2017	59	82	41	343	65	3	1	38	28	659
	2018	60	83	41	347	66	3	1	39	28	668
	2019	61	84	42	352	67	3	1	39	28	677
	2020	62	85	42	357	68	3	1	40	29	686
	2021	63	86	43	361	69	3	1	40	29	695
	2022	63	87	44	366	70	3	1	41	30	704
	2023	64	88	44	371	71	3	1	42	30	713
	2024	65	89	45	375	72	3	1	42	30	722
	2025	66	90	45	380	72	3	1	43	31	

Appendix B

Energy Efficiency Measures Database

Residential Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
SH.1	Space Heat	Energy Star or better heat pump upgrade								
				Existing	20	0.000	0.000	$ 2,147.89	$ -	$ -
				Base	20	0.215	0.000	$ 2,807.46	$ -	$ -
				High Efficiency	20	0.291	0.000	$ 3,467.03	$ -	$ -
SH.2	Space Heat	Furnace upgrades (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ 729.28	$ -	$ -
				High Efficiency	20	0.025	0.000	$ 1,655.13	$ -	$ -
SH.3	Space Heat	Duct Insulation (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.246	0.000	$ 565.56	$ -	$ -
SH.4	Space Heat	Duct Sealing (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.246	0.000	$ 781.37	$ -	$ -
SH.5	Space Heat	Programmable Thermostat (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.068	0.000	$ 71.94	$ -	$ -
SH.6	Space Heat	Air sealing-caulking, weatherstripping, hole sealing (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	13	0.000	0.000	$ -	$ -	$ -
				High Efficiency	13	0.138	0.000	$ 221.02	$ -	$ -
SH.7	Space Heat	Energy Star or better windows (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 26.67	$ -	$ -
				High Efficiency	25	0.029	0.000	$ 31.68	$ -	$ -
SH.8	Space Heat	Shell insulation upgrades (Wall and Slab, Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 0.58	$ -	$ -
				High Efficiency	25	0.188	0.000	$ 0.88	$ -	$ -
SH.9	Space Heat	Insulated metal or fiberglass doors (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.015	0.000	$ 117.83	$ -	$ -
SH.10	Space Heat	Leakproof Duct Fittings								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.260	0.000	$ 131.62	$ -	$ -
SH.11	Space Heat	Solid State Refrigeration (Cool Chips)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 98.71	$ -	$ -
FF.1	Furnace Fan	Higher efficiency motor								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.125	0.000	$ 124.03	$ -	$ -
AC.1	Central A/C	Central A/C - various equipment retrofits (EER & tonnage)								
				Existing	15	0.000	0.000	$ 290.22	$ 461.38	$ -
				Base	15	0.236	0.250	$ 404.33	$ 461.38	$ -
				High Efficiency	15	0.337	0.350	$ 576.40	$ 461.38	$ -
AC.2	Central A/C	Refrigerant charge testing and recharging								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.070	0.053	$ 124.03	$ -	$ -

Residential Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
AC.3	Central A/C	Filter cleaning and/or replacement								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	5	0.000	0.000	$ -	$ -	$ -
				High Efficiency	5	0.025	0.013	$ 124.03	$ -	$ -
AC.4	Central A/C	Duct Insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.068	0.072	$ 565.56	$ -	$ -
AC.5	Central A/C	Duct Sealing								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.135	0.143	$ 781.37	$ -	$ -
AC.6	Central A/C	Programmable Thermostat								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.157	0.000	$ 71.94	$ -	$ -
AC.7	Central A/C	Air sealing (caulking, weatherstripping, hole sealing)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	13	0.000	0.000	$ -	$ -	$ -
				High Efficiency	13	0.135	0.169	$ 221.02	$ -	$ -
AC.8	Central A/C	Shell insulation upgrades								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 0.58	$ -	$ -
				High Efficiency	25	0.045	0.052	$ 0.88	$ -	$ -
AC.9	Central A/C	Energy Star or better windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 26.67	$ -	$ -
				High Efficiency	25	0.281	0.117	$ 31.68	$ -	$ -
AC.10	Central A/C	Solar control glazing								
				Existing	1	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 1.24	$ -	$ -
				High Efficiency	1	0.000	0.000	$ 1.24	$ -	$ -
AC.11	Central A/C	Solar gain controls such as exterior shades								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.270	0.091	$ 89.56	$ -	$ -
AC.12	Central A/C	Insulated metal or fiberglass doors								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.011	0.013	$ 117.83	$ -	$ -
AC.13	Central A/C	Advanced Unitary HVAC compressors								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.236	0.250	$ 404.33	$ -	$ -
				High Efficiency	18	0.401	0.401	$ 1,241.50	$ -	$ -
AC.14	Central A/C	Leakproof Duct Fittings								
				Existing	1	0.000	0.000	$ -	$ -	$ -
				Base	30	0.000	0.000	$ 124.03	$ -	$ -
				High Efficiency	30	0.260	0.260	$ 124.03	$ -	$ -
AC.15	Central A/C	Solid State Refrigeration (Cool Chips)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.180	$ 65.81	$ -	$ -
RAC.1	Room A/C	Room A/C - various equipment retrofits (EER & tonnage)								
				Existing	15	0.000	0.000	$ 713.29	$ -	$ -
				Base	15	0.175	0.175	$ 751.87	$ -	$ -
				High Efficiency	15	0.238	0.238	$ 871.50	$ -	$ -

Residential Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
RAC.2	Room A/C	Refrigerant charge testing and recharging								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.050	0.025	$ 124.03	$ -	$ -
RAC.3	Room A/C	Filter cleaning and/or replacement								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	5	0.000	0.000	$ -	$ -	$ -
				High Efficiency	5	0.050	0.025	$ 124.03	$ -	$ -
RAC.4	Room A/C	Air sealing (caulking, weatherstripping, hole sealing)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	13	0.000	0.000	$ -	$ -	$ -
				High Efficiency	13	0.135	0.169	$ 221.02	$ -	$ -
RAC.5	Room A/C	Attic, roof, wall, perimeter, knee wall, underfloor insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 0.58	$ -	$ -
				High Efficiency	25	0.045	0.052	$ 0.88	$ -	$ -
RAC.6	Room A/C	Energy Star or better windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 26.67	$ -	$ -
				High Efficiency	25	0.281	0.117	$ 31.68	$ -	$ -
RAC.7	Room A/C	Solar control glazing								
				Existing	1	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 1.24	$ -	$ -
				High Efficiency	1	0.000	0.000	$ 1.24	$ -	$ -
RAC.8	Room A/C	Solar gain controls such as exterior shades								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.270	0.091	$ 89.56	$ -	$ -
RAC.9	Room A/C	Insulated metal or fiberglass doors								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.011	0.013	$ 117.83	$ -	$ -
RAC.10	Room A/C	Advanced Room AC								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.100	0.100	$ 124.03	$ -	$ -
L.1	Lighting	Compact fluorescent lamps (CFLs)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 0.47	$ -	$ -
				High Efficiency	8	0.751	0.751	$ 10.91	$ -	$ -
L.2	Lighting	LED Lighting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 0.47	$ -	$ -
				High Efficiency	13	0.620	0.620	$ 13.63	$ -	$ -
R.1	Refrigerator	Energy Star or better refrigerator								
				Existing	15	0.000	0.000	$ 1,046.78	$ -	$ -
				Base	15	0.300	0.300	$ 1,374.21	$ -	$ -
				High Efficiency	15	0.405	0.405	$ 1,540.10	$ -	$ -
R.2	Refrigerator	1 kWh/Day Refrigerator								
				Existing	0	0.000	0.000	$ 1,046.78	$ -	$ -
				Base	15	0.300	0.300	$ 1,374.21	$ -	$ -
				High Efficiency	15	0.510	0.510	$ 1,466.34	$ -	$ -
F.1	Freezer	Energy Star or better freezer								
				Existing	15	0.000	0.000	$ 1,046.78	$ -	$ -
				Base	15	0.141	0.141	$ 1,374.21	$ -	$ -
				High Efficiency	15	0.227	0.227	$ 1,540.10	$ -	$ -

Residential Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
F.2	Freezer	1 kWh/Day Refrigerator								
				Existing	15	0.000	0.000	$ -	$ -	$ -
				Base	15	0.141	0.141	$ 1,374.21	$ -	$ -
				High Efficiency	15	0.510	0.510	$ 1,466.34	$ -	$ -
DW.1	Dishwasher	Energy Star Dishwasher - Electric DHW								
				Existing	13	0.000	0.000	$ 372.08	$ -	$ -
				Base	13	0.130	0.130	$ 522.15	$ -	$ -
				High Efficiency	13	0.260	0.260	$ 775.16	$ -	$ -
DW.2	Dishwasher	Advanced Energy Star Dishwasher - Electric DHW								
				Existing	13	0.000	0.000	$ -	$ -	$ -
				Base	13	0.130	0.130	$ -	$ -	$ -
				High Efficiency	13	0.400	0.400	$ 93.02	$ -	$ -
WH.1	Water Heat	Heater efficiency upgrades (Elec)								
				Existing	15	0.000	0.000	$ -	$ -	$ -
				Base	15	0.048	0.048	$ 223.25	$ -	$ -
				High Efficiency	15	0.099	0.099	$ 285.26	$ -	$ -
WH.2	Water Heat	Pipe Wrap (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.040	0.040	$ 1.67	$ 1.67	$ -
WH.3	Water Heat	Water heat tank wraps and bottom boards (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.100	0.100	$ 21.08	$ -	$ -
WH.4	Water Heat	Tank temperature setback (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	5	0.000	0.000	$ -	$ -	$ -
				High Efficiency	5	0.055	0.055	$ -	$ 31.01	$ -
WH.5	Water Heat	Low Flow Showerheads (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.075	0.075	$ 24.81	$ -	$ -
WH.6	Water Heat	Faucet Aerators (Elec)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.030	0.030	$ 5.98	$ -	$ -
WH.7	Water Heat	Vapor-compression cycle								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.048	0.000	$ 223.25	$ -	$ -
				High Efficiency	15	0.000	0.000	$ 354.87	$ -	$ -
CD.1	Clothes Dryer	Energy Star or better clothes dryer (Elec)								
				Existing	18	0.000	0.000	$ 248.05	$ -	$ -
				Base	18	0.050	0.050	$ 406.81	$ -	$ -
				High Efficiency	18	0.098	0.098	$ 597.81	$ -	$ -
CD.2	Clothes Dryer	Advanced Energy Star or better clothes dryer (Elec)								
				Existing	18	0.000	0.000	$ -	$ -	$ -
				Base	18	0.050	0.050	$ 1,240.26	$ -	$ -
				High Efficiency	18	0.200	0.200	$ 1,241.50	$ -	$ -
M.1	Misc	Energy Star Clothes Washers - All Electric								
				Existing	15	0.000	0.000	$ 556.88	$ -	$ -
				Base	15	0.530	0.530	$ 958.72	$ -	$ -
				High Efficiency	15	0.630	0.630	$ 1,020.74	$ -	$ -
M.2	Misc	Energy Star Clothes Washers - All Electric								
				Existing	15	0.000	0.000	$ -	$ -	$ -
				Base	15	0.530	0.530	$ 1,240.26	$ -	$ -
				High Efficiency	15	0.800	0.800	$ 1,364.29	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
H.1	Heating	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.334	0.166	$ 0.87	$ -	$ -
H.2	Heating	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	-0.004	0.002	$ 0.78	$ -	$ -
H.3	Heating	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.088	0.118	$ 34.11	$ -	$ -
H.4	Heating	Infiltration Reduction								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.064	0.105	$ 0.62	$ -	$ -
H.6	Heating	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
H.7	Heating	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.180	$ 65.81	$ -	$ -
V.1	Ventilation	Premium-efficiency motors								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ 57.07	$ -	$ -
				High Efficiency	15	0.057	0.060	$ 68.80	$ -	$ -
V.2	Ventilation	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.060	0.012	$ 0.50	$ -	$ -
V.3	Ventilation	Automatic OA reduction control								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.100	0.010	$ 352.23	$ 601.53	$ -
V.4	Ventilation	Unoccupied OA reduction								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.050	0.005	$ 124.03	$ -	$ -
V.5	Ventilation	Installation of nighttime pre-cooling controls and systems								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.000	0.234	$ 124.03	$ -	$ -
V.6	Ventilation	Installation of outside air reset controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.000	0.000	$ 1.24	$ -	$ -
V.7	Ventilation	Reducing minimum outside air requirements								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.000	0.000	$ 1.24	$ -	$ -
V.8	Ventilation	CV to VAV conversion								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.300	0.300	$ 124.03	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	College							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	18	0.000	0.000	$ -	$ -	$ -
				High Efficiency	18	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	School							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Grocery							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Restaurant							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Health							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Lodging							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Office							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Apartment							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Retail							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Warehouse							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
C.1	Cooling	High-efficiency chillers	Misc & Agriculture							
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Advanced Unitary HVAC Compressors								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.190	0.190	$ 197.43	$ -	$ -
C.13	Cooling	Leakproof Duct Fittings								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.14	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.000	$ 65.81	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	College							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	School							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Grocery							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Restaurant							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Health							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Lodging							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Office							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Apartment							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Retail							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Warehouse							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')	Misc & Agriculture							
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.300	0.300	$ 0.00	$ -	$ -
X.1	Ext Lighting	Outdoor lighting controls for HID (photocell/timeclock)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	8	0.000	0.000	$ -	$ -	$ -
				High Efficiency	8	0.271	0.000	$ 63.25	$ 69.45	$ -
X.2	Ext Lighting	Outdoor lighting controls for incandescent (photocell/timeclock)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	8	0.000	0.000	$ -	$ -	$ -
				High Efficiency	8	0.271	0.000	$ 63.25	$ 69.45	$ -
X.3	Ext Lighting	Outdoor lighting controls for fluorescent (photocell/timeclock)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	8	0.000	0.000	$ -	$ -	$ -
				High Efficiency	8	0.271	0.000	$ 63.25	$ 69.45	$ -
X.4	Ext Lighting	High-intensity discharge lamps (mercury vapor to hi-pres sodium)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.451	0.451	$ 110.38	$ 74.42	$ -
X.5	Ext Lighting	High-intensity discharge lamps (incandescent to hi-pres sodium)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.667	0.667	$ 110.38	$ 74.42	$ -
X.6	Ext Lighting	T8 lamps with electronic ballasts (2L4')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
X.7	Ext Lighting	White LED Lamps								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.650	$ 69.76	$ -	$ -
R.1	Refrigeration	High-efficiency fan motors								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.120	0.120	$ 1.44	$ -	$ -
R.2	Refrigeration	Strip curtains for walk-ins								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ -	$ -	$ -
				High Efficiency	4	0.040	0.040	$ 0.06	$ -	$ -
R.3	Refrigeration	Night covers for display cases								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	5	0.000	0.000	$ -	$ -	$ -
				High Efficiency	5	0.060	0.000	$ 0.14	$ -	$ -
R.4	Refrigeration	Evaporator fan controller for MT walk-ins								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	5	0.000	0.000	$ -	$ -	$ -
				High Efficiency	5	0.010	0.010	$ 0.06	$ -	$ -

Commercial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
R.5	Refrigeration	Efficiency compressor motor retrofit								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.070	0.070	$ 0.11	$ -	$ -
R.6	Refrigeration	Compressor VSD retrofit								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.060	0.030	$ 0.50	$ -	$ -
R.7	Refrigeration	Floating head pressure controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	14	0.000	0.000	$ -	$ -	$ -
				High Efficiency	14	0.070	0.000	$ 0.15	$ -	$ -
R.8	Refrigeration	Refrigeration commissioning								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.050	0.050	$ 0.22	$ -	$ -
R.9	Refrigeration	Demand hot gas defrost								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.030	0.030	$ 0.04	$ -	$ -
R.10	Refrigeration	Demand defrost electric								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.080	0.080	$ 0.04	$ -	$ -
R.11	Refrigeration	Anti-sweat (humidistat) controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.050	0.020	$ 0.20	$ -	$ -
O.1	Office Equip	Power management enabling - PC								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ -	$ -	$ -
				High Efficiency	4	0.410	0.144	$ -	$ 17.36	$ -
O.2	Office Equip	Power management enabling - monitor								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ -	$ -	$ -
				High Efficiency	4	0.730	0.256	$ -	$ 9.92	$ -
O.3	Office Equip	Power management enabling - copier								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ -	$ -	$ -
				High Efficiency	4	0.640	0.224	$ -	$ 55.81	$ -
O.4	Office Equip	Network power management enabling - monitor								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ -	$ -	$ -
				High Efficiency	4	0.730	0.256	$ -	$ 4.96	$ -
O.5	Office Equip	External hardware control - monitors								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ -	$ -	$ -
				High Efficiency	4	0.730	0.000	$ 76.90	$ 40.93	$ -
O.6	Office Equip	External hardware control - printers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ -	$ -	$ -
				High Efficiency	4	0.540	0.000	$ 173.64	$ 40.93	$ -
O.7	Office Equip	Nighttime shutdown - printers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ -	$ -	$ -
				High Efficiency	4	0.540	0.000	$ -	$ 690.42	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
O.8	Office Equip	LCD monitor								
				Existing	4	0.000	0.000	$ -	$ -	$ -
				Base	4	0.000	0.000	$ 186.04	$ -	$ -
				High Efficiency	4	0.500	0.500	$ 496.11	$ -	$ -
O.9	Office Equip	1-watt standby power for (Home) Appliances								
				Existing	0	0.000	0.000	$ -	$ -	$ -
				Base	7	0.000	0.000	$ -	$ -	$ -
				High Efficiency	7	0.300	0.300	$ 39.49	$ -	$ -
W.1	Water	Heater efficiency upgrade								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.250	0.250	$ 0.30	$ -	$ -
W.2	Water	Instanteous Water Heater <=200 MBTUH								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.100	0.100	$ 0.10	$ -	$ -
W.3	Water	Circulation Pump Timelocks								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.030	0.030	$ 0.01	$ -	$ -
W.4	Water	Tank Insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.095	0.095	$ 0.03	$ -	$ -
W.5	Water	Pipe Insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.020	0.020	$ 0.02	$ -	$ -
W.6	Water	Low Flow Showerheads								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.023	0.023	$ 0.02	$ -	$ -
W.7	Water	Faucet Aerator								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.020	0.020	$ 0.01	$ -	$ -
K.1	Cooking	Efficient Infrared Griddle								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.023	0.023	$ 124.03	$ -	$ -
K.2	Cooking	Convection Oven								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.047	0.047	$ 124.03	$ -	$ -
K.3	Cooking	Infrared Conveyor Oven								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.055	0.055	$ 124.03	$ -	$ -
K.4	Cooking	Infrared Fryer								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.090	0.090	$ 124.03	$ -	$ -
K.5	Cooking	Power Burner Oven								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.024	0.024	$ 124.03	$ -	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
K.6	Cooking	Power Burner Fryer								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.024	0.024	$ 124.03	$ -	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
H.1	HVAC/Heating	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.334	0.166	$ 0.87	$ -	$ -
H.2	HVAC/Heating	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	-0.004	0.002	$ 0.78	$ -	$ -
H.3	HVAC/Heating	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.088	0.118	$ 34.11	$ -	$ -
H.4	HVAC/Heating	Infiltration Reduction								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.064	0.105	$ 0.62	$ -	$ -
H.6	HVAC/Heating	Leakproof Duct Fittings								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	30	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	30	0.210	0.000	$ 163.24	$ -	$ -
H.7	HVAC/Heating	Solid State Refrigeration (Cool Chips)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.180	0.105	$ 65.81	$ -	$ -
V.1	HVAC/Ventilation	Premium-efficiency motors								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ 57.07	$ -	$ -
				High Efficiency	15	0.057	0.060	$ 68.80	$ -	$ -
V.2	HVAC/Ventilation	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.060	0.012	$ 0.50	$ -	$ -
V.3	HVAC/Ventilation	Automatic OA reduction control								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.100	0.010	$ 352.23	$ 601.53	$ -
V.4	HVAC/Ventilation	Unoccupied OA reduction								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.050	0.005	$ 124.03	$ -	$ -
V.5	HVAC/Ventilation	Installation of nighttime pre-cooling controls and systems								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.000	0.234	$ 124.03	$ -	$ -
V.6	HVAC/Ventilation	Installation of outside air reset controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.000	0.000	$ 1.24	$ -	$ -
V.7	HVAC/Ventilation	Reducing minimum outside air requirements								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.000	0.000	$ 1.24	$ -	$ -
V.8	HVAC/Ventilation	CV to VAV conversion								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.300	0.300	$ 124.03	$ -	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
V.9	HVAC/Ventilation	Advanced Unitary HVAC Compressors								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	18	0.000	0.000	$ -	$ -	$ -
				High Efficiency	18	0.190	0.190	$ 197.43	$ -	$ -
C.1	Cooling	High-efficiency chillers								
				Existing	20	0.000	0.000	$ 287.74	$ -	$ -
				Base	20	0.108	0.108	$ 313.79	$ -	$ -
				High Efficiency	20	0.159	0.230	$ 350.99	$ -	$ -
C.2	Cooling	High-efficiency packaged DX A/C								
				Existing	15	0.000	0.000	$ 670.49	$ 252.52	$ -
				Base	15	0.118	0.118	$ 783.54	$ 252.52	$ -
				High Efficiency	15	0.235	0.235	$ 882.08	$ 252.52	$ -
C.3	Cooling	Energy management controls								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.083	0.093	$ 1,385.37	$ -	$ -
C.4	Cooling	Window treatment								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	11	0.000	0.000	$ -	$ -	$ -
				High Efficiency	11	0.155	0.184	$ 0.87	$ -	$ -
C.5	Cooling	Improved maintenance and diagnostics								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.200	0.200	$ 930.20	$ -	$ -
C.6	Cooling	Cool (reflective) rooftops								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.005	0.000	$ 0.78	$ -	$ -
C.7	Cooling	Variable-speed drives								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.060	0.060	$ 80.62	$ -	$ -
C.8	Cooling	Installation of low-E glass or multiple glazed windows								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ 31.63	$ -	$ -
				High Efficiency	25	0.136	0.134	$ 34.11	$ -	$ -
C.9	Cooling	Installation of wall, roof, or ceiling insulation								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	20	0.000	0.000	$ -	$ -	$ -
				High Efficiency	20	0.000	0.001	$ 0.62	$ -	$ -
C.10	Cooling	Optimize chilled water and condenser water setting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	3	0.000	0.000	$ -	$ -	$ -
				High Efficiency	3	0.010	0.010	$ 124.03	$ -	$ -
C.11	Cooling	Chiller economizers (water side), or air side economizers								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	12	0.000	0.000	$ -	$ -	$ -
				High Efficiency	12	0.250	0.000	$ 94.05	$ -	$ -
C.12	Cooling	Leakproof Duct Fittings								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	25	0.000	0.000	$ -	$ -	$ -
				High Efficiency	25	0.210	0.210	$ 131.62	$ -	$ -
C.13	Cooling	Solid State Refrigeration (Cool Chips)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	1	0.180	0.180	$ 65.81	$ -	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
PC.1	Process Cooling	Process Cooling (2.26)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.328	0.328	$ 0.09	$ -	$ -
PC.2	Process Cooling	Advanced Process Cooling								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.150	0.150	$ 0.09	$ -	$ -
PH.1	Process Heating & Boiler Fuel	Furnaces, Ovens, & Directly Fired Operations (2.11)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.282	0.282	$ 0.02	$ -	$ -
PH.2	Process Heating & Boiler Fuel	Boilers (2.12)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.367	0.367	$ 0.06	$ -	$ -
PH.3	Process Heating & Boiler Fuel	Steam Thermal Systems (2.21)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.431	0.431	$ 0.04	$ -	$ -
PH.4	Process Heating & Boiler Fuel	Heating Thermal Systems (2.22)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.249	0.249	$ 0.08	$ -	$ -
PH.5	Process Heating & Boiler Fuel	Heat Treating Thermal Systems (2.23)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.340	0.340	$ 0.08	$ -	$ -
PH.6	Process Heating & Boiler Fuel	Heat Recovery for Thermal Systems (2.24)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.772	0.772	$ 0.22	$ -	$ -
PH.7	Process Heating & Boiler Fuel	Heat Containment for Thermal Systems (2.25)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.119	0.119	$ 0.04	$ -	$ -
PH.8	Process Heating & Boiler Fuel	Drying (2.27)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.389	0.389	$ 0.08	$ -	$ -
PH.9	Process Heating & Boiler Fuel	Thermal System Design (2.511)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.404	0.404	$ 0.10	$ -	$ -
PH.10	Process Heating & Boiler Fuel	Advanced Process Heating								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.150	0.150	$ 0.50	$ -	$ -
L.1	Int Lighting	T8 lamps with electronic ballasts (2L4')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
L.2	Int Lighting	Reflectors for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.542	0.542	$ 45.89	$ 16.12	$ -

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
L.3	Int Lighting	Perimeter dimming for 4' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.385	0.795	$ 130.23	$ 55.81	$ -
L.4	Int Lighting	Occupancy sensors for 4' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 15.19	$ 1.95	$ -
L.5	Int Lighting	T8 lamps with electronic ballasts (2L8')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.203	0.203	$ 73.26	$ 21.08	$ -
L.6	Int Lighting	Reflectors for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.447	0.447	$ 89.30	$ 21.08	$ -
L.7	Int Lighting	Perimeter dimming for 8' fluorescent								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.114	0.114	$ 59.53	$ 21.08	$ -
				High Efficiency	16	0.335	0.778	$ 130.23	$ 55.81	$ -
L.8	Int Lighting	Occupancy sensors for 8' fluorescent								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.200	0.200	$ 30.39	$ 3.91	$ -
L.9	Int Lighting	Compact flourescent lamp (modular)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ 2.48	$ 4.96	$ -
				High Efficiency	8	0.760	0.760	$ 27.29	$ 6.20	$ -
L.10	Int Lighting	High-intensity discharge lamps (incandescent to metal halide)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.550	0.550	$ 281.54	$ 74.42	$ -
L.11	Int Lighting	LED Exit Signs								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	10	0.000	0.000	$ -	$ -	$ -
				High Efficiency	10	0.900	0.900	$ 31.01	$ 16.12	$ -
L.12	Int Lighting	White LED Lamps								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.000	$ 69.76	$ 3.91	$ -
L.13	Int Lighting	Scotopic Lighting								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.300	0.000	$ 0.00	$ -	$ -
X.1	Ext Lighting	Outdoor lighting controls for HID (photocell/timeclock)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	8	0.000	0.000	$ -	$ -	$ -
				High Efficiency	8	0.271	0.000	$ 63.25	$ 69.45	$ -
X.2	Ext Lighting	Outdoor lighting controls for incandescent (photocell/timeclock)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	8	0.000	0.000	$ -	$ -	$ -
				High Efficiency	8	0.271	0.000	$ 63.25	$ 69.45	$ -
X.3	Ext Lighting	Outdoor lighting controls for fluorescent (photocell/timeclock)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	8	0.000	0.000	$ -	$ -	$ -
				High Efficiency	8	0.271	0.000	$ 63.25	$ 69.45	$ -

Industrial Energy Efficiency Measures Database

ID	End Use	Measure	Subsector	Efficiency	Measure life	Energy Savings Factor	Demand Savings Factor	Full Capital Cost	Full Install Cost	Full O&M Cost
X.4	Ext Lighting	High-intensity discharge lamps (mercury vapor to hi-pres sodium)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.451	0.113	$ 110.38	$ 74.42	$ -
X.5	Ext Lighting	High-intensity discharge lamps (incandescent to hi-pres sodium)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	16	0.000	0.000	$ -	$ -	$ -
				High Efficiency	16	0.667	0.167	$ 110.38	$ 74.42	$ -
X.6	Ext Lighting	T8 lamps with electronic ballasts (2L4')								
				Existing	16	0.000	0.000	$ -	$ -	$ -
				Base	16	0.181	0.181	$ 22.49	$ 11.66	$ -
				High Efficiency	16	0.333	0.333	$ 27.67	$ 11.66	$ -
X.8	Ext Lighting	White LED Lamps								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	1	0.000	0.000	$ -	$ -	$ -
				High Efficiency	6	0.650	0.000	$ 69.76	$ 74.42	$ -
PM.1	Process Machine Drive	Motors (2.41)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.043	0.043	$ 0.12	$ -	$ -
PM.2	Process Machine Drive	Air Compressors (2.42)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.032	0.032	$ 0.02	$ -	$ -
PM.3	Process Machine Drive	Other Equipment (2.43)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.037	0.037	$ 0.14	$ -	$ -
PM.4	Process Machine Drive	Mechanical System Design (2.512)								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.053	0.053	$ 0.08	$ -	$ -
PM.5	Process Machine Drive	Advanced Machine Drive								
				Existing		0.000	0.000	$ -	$ -	$ -
				Base	15	0.000	0.000	$ -	$ -	$ -
				High Efficiency	15	0.150	0.150	$ 0.50	$ -	$ -

Appendix C

Initial Technology Market Shares

Residential Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
All	Space Heat (Elec)	Central Forced Air (Elec)	1.8%
All	Space Heat (Elec)	Electric Baseboard (Elec)	1.8%
All	Space Heat (Elec)	Hot Water Radiator (Elec)	1.8%
All	Space Heat (Elec)	Heat Pump (Elec)	1.5%
All	Supp. Space Heat (Elec)	Supplemental Heater (Elec)	0.1%
All	Furnace Fan	Furnace Fan	10.0%
All	Central A/C	Central Air Conditioner	1.7%
All	Central A/C	Heat Pump	1.7%
All	Room A/C	Room Air Conditioner	2.7%
All	Lights	Incandescent	0.4%
All	Refrigerator	Refrigerator	28.9%
All	Freezer	Freezer	47.8%
All	Dishwasher	Dishwasher	29.8%
All	Water Heat (Elec)	Water Heater (Elec)	2.2%
All	Clothes Dryer (Elec)	Clothes Dryer (Elec)	40.6%
All	ElecMotors	ElecMotors	0.1%
All	ClothesWash	Clothes Washer	40.6%

Commercial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Educational Services	Heating	Cntrl - HP	1.1%
Educational Services	Heating	Cntrl - RTU/Furn	1.1%
Educational Services	Heating	Unitary	0.8%
Educational Services	Ventilation	Motor	3.5%
Educational Services	Ventilation	Motor w/VFD	4.3%
Educational Services	Cooling	Chillers	1.2%
Educational Services	Cooling	DX Units	4.3%
Educational Services	Cooling	Room AC	2.6%
Educational Services	Int. Lighting	4' Fluor	1.1%
Educational Services	Int. Lighting	8' Fluor	1.3%
Educational Services	Int. Lighting	Incand.	0.3%
Educational Services	Int. Lighting	Exit Signs	0.5%
Educational Services	Ext Lighting	HID	0.5%
Educational Services	Ext Lighting	Fluor	1.4%
Educational Services	Ext Lighting	Incand.	0.4%
Educational Services	Refrigeration	Compressors	10.0%
Educational Services	Refrigeration	Fans/Motors	10.0%
Educational Services	Refrigeration	Other	10.0%
Educational Services	Office Equip	CPUs	1.4%
Educational Services	Office Equip	Monitors	0.6%
Educational Services	Office Equip	Copy/Fax	0.7%
Educational Services	Office Equip	Other	10.0%
Educational Services	Water	All	10.0%
Educational Services	Cooking	All	10.0%
Educational Services	Misc	Technology 1	10.0%
Educational Services	Misc	Technology 2	10.0%
Educational Services	Misc	Technology 3	10.0%
Arts, Entertainment and Recreation	Heating	Cntrl - HP	1.1%
Arts, Entertainment and Recreation	Heating	Cntrl - RTU/Furn	1.1%
Arts, Entertainment and Recreation	Heating	Unitary	0.8%
Arts, Entertainment and Recreation	Ventilation	Motor	3.5%
Arts, Entertainment and Recreation	Ventilation	Motor w/VFD	4.3%
Arts, Entertainment and Recreation	Cooling	Chillers	1.2%
Arts, Entertainment and Recreation	Cooling	DX Units	4.3%
Arts, Entertainment and Recreation	Cooling	Room AC	2.6%
Arts, Entertainment and Recreation	Int. Lighting	4' Fluor	1.1%
Arts, Entertainment and Recreation	Int. Lighting	8' Fluor	1.3%
Arts, Entertainment and Recreation	Int. Lighting	Incand.	0.3%
Arts, Entertainment and Recreation	Int. Lighting	Exit Signs	0.5%
Arts, Entertainment and Recreation	Ext Lighting	HID	0.5%
Arts, Entertainment and Recreation	Ext Lighting	Fluor	1.4%
Arts, Entertainment and Recreation	Ext Lighting	Incand.	0.4%
Arts, Entertainment and Recreation	Refrigeration	Compressors	10.0%
Arts, Entertainment and Recreation	Refrigeration	Fans/Motors	10.0%
Arts, Entertainment and Recreation	Refrigeration	Other	10.0%
Arts, Entertainment and Recreation	Office Equip	CPUs	1.4%
Arts, Entertainment and Recreation	Office Equip	Monitors	0.6%
Arts, Entertainment and Recreation	Office Equip	Copy/Fax	0.7%
Arts, Entertainment and Recreation	Office Equip	Other	10.0%

Commercial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Arts, Entertainment and Recreation	Water	All	10.0%
Arts, Entertainment and Recreation	Cooking	All	10.0%
Arts, Entertainment and Recreation	Misc	Technology 1	10.0%
Arts, Entertainment and Recreation	Misc	Technology 2	10.0%
Arts, Entertainment and Recreation	Misc	Technology 3	10.0%
Information & Cultural Industries	Heating	Cntrl - HP	1.1%
Information & Cultural Industries	Heating	Cntrl - RTU/Furn	1.1%
Information & Cultural Industries	Heating	Unitary	0.8%
Information & Cultural Industries	Ventilation	Motor	3.5%
Information & Cultural Industries	Ventilation	Motor w/VFD	4.3%
Information & Cultural Industries	Cooling	Chillers	1.2%
Information & Cultural Industries	Cooling	DX Units	4.3%
Information & Cultural Industries	Cooling	Room AC	2.6%
Information & Cultural Industries	Int. Lighting	4' Fluor	1.1%
Information & Cultural Industries	Int. Lighting	8' Fluor	1.3%
Information & Cultural Industries	Int. Lighting	Incand.	0.3%
Information & Cultural Industries	Int. Lighting	Exit Signs	0.5%
Information & Cultural Industries	Ext Lighting	HID	0.5%
Information & Cultural Industries	Ext Lighting	Fluor	1.4%
Information & Cultural Industries	Ext Lighting	Incand.	0.4%
Information & Cultural Industries	Refrigeration	Compressors	10.0%
Information & Cultural Industries	Refrigeration	Fans/Motors	10.0%
Information & Cultural Industries	Refrigeration	Other	10.0%
Information & Cultural Industries	Office Equip	CPUs	1.4%
Information & Cultural Industries	Office Equip	Monitors	0.6%
Information & Cultural Industries	Office Equip	Copy/Fax	0.7%
Information & Cultural Industries	Office Equip	Other	10.0%
Information & Cultural Industries	Water	All	10.0%
Information & Cultural Industries	Cooking	All	10.0%
Information & Cultural Industries	Misc	Technology 1	10.0%
Information & Cultural Industries	Misc	Technology 2	10.0%
Information & Cultural Industries	Misc	Technology 3	10.0%
Accommodation & Food Services	Heating	Cntrl - HP	1.1%
Accommodation & Food Services	Heating	Cntrl - RTU/Furn	1.1%
Accommodation & Food Services	Heating	Unitary	0.8%
Accommodation & Food Services	Ventilation	Motor	3.5%
Accommodation & Food Services	Ventilation	Motor w/VFD	4.3%
Accommodation & Food Services	Cooling	Chillers	1.2%
Accommodation & Food Services	Cooling	DX Units	4.3%
Accommodation & Food Services	Cooling	Room AC	2.6%
Accommodation & Food Services	Int. Lighting	4' Fluor	1.1%
Accommodation & Food Services	Int. Lighting	8' Fluor	1.3%
Accommodation & Food Services	Int. Lighting	Incand.	0.3%
Accommodation & Food Services	Int. Lighting	Exit Signs	0.5%
Accommodation & Food Services	Ext Lighting	HID	0.5%
Accommodation & Food Services	Ext Lighting	Fluor	1.4%
Accommodation & Food Services	Ext Lighting	Incand.	0.4%
Accommodation & Food Services	Refrigeration	Compressors	10.0%

Commercial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Accommodation & Food Services	Refrigeration	Fans/Motors	10.0%
Accommodation & Food Services	Refrigeration	Other	10.0%
Accommodation & Food Services	Office Equip	CPUs	1.4%
Accommodation & Food Services	Office Equip	Monitors	0.6%
Accommodation & Food Services	Office Equip	Copy/Fax	0.7%
Accommodation & Food Services	Office Equip	Other	10.0%
Accommodation & Food Services	Water	All	10.0%
Accommodation & Food Services	Cooking	All	10.0%
Accommodation & Food Services	Misc	Technology 1	10.0%
Accommodation & Food Services	Misc	Technology 2	10.0%
Accommodation & Food Services	Misc	Technology 3	10.0%
Health Care & Social Assistance	Heating	Cntrl - HP	1.1%
Health Care & Social Assistance	Heating	Cntrl - RTU/Furn	1.1%
Health Care & Social Assistance	Heating	Unitary	0.8%
Health Care & Social Assistance	Ventilation	Motor	3.5%
Health Care & Social Assistance	Ventilation	Motor w/VFD	4.3%
Health Care & Social Assistance	Cooling	Chillers	1.2%
Health Care & Social Assistance	Cooling	DX Units	4.3%
Health Care & Social Assistance	Cooling	Room AC	2.6%
Health Care & Social Assistance	Int. Lighting	4' Fluor	1.1%
Health Care & Social Assistance	Int. Lighting	8' Fluor	1.3%
Health Care & Social Assistance	Int. Lighting	Incand.	0.3%
Health Care & Social Assistance	Int. Lighting	Exit Signs	0.5%
Health Care & Social Assistance	Ext Lighting	HID	0.5%
Health Care & Social Assistance	Ext Lighting	Fluor	1.4%
Health Care & Social Assistance	Ext Lighting	Incand.	0.4%
Health Care & Social Assistance	Refrigeration	Compressors	10.0%
Health Care & Social Assistance	Refrigeration	Fans/Motors	10.0%
Health Care & Social Assistance	Refrigeration	Other	10.0%
Health Care & Social Assistance	Office Equip	CPUs	1.4%
Health Care & Social Assistance	Office Equip	Monitors	0.6%
Health Care & Social Assistance	Office Equip	Copy/Fax	0.7%
Health Care & Social Assistance	Office Equip	Other	10.0%
Health Care & Social Assistance	Water	All	10.0%
Health Care & Social Assistance	Cooking	All	10.0%
Health Care & Social Assistance	Misc	Technology 1	10.0%
Health Care & Social Assistance	Misc	Technology 2	10.0%
Health Care & Social Assistance	Misc	Technology 3	10.0%
Wholesale Trade	Heating	Cntrl - HP	1.1%
Wholesale Trade	Heating	Cntrl - RTU/Furn	1.1%
Wholesale Trade	Heating	Unitary	0.8%
Wholesale Trade	Ventilation	Motor	3.5%
Wholesale Trade	Ventilation	Motor w/VFD	4.3%
Wholesale Trade	Cooling	Chillers	1.2%
Wholesale Trade	Cooling	DX Units	4.3%
Wholesale Trade	Cooling	Room AC	2.6%
Wholesale Trade	Int. Lighting	4' Fluor	1.1%
Wholesale Trade	Int. Lighting	8' Fluor	1.3%

Commercial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Wholesale Trade	Int. Lighting	Incand.	0.3%
Wholesale Trade	Int. Lighting	Exit Signs	0.5%
Wholesale Trade	Ext Lighting	HID	0.5%
Wholesale Trade	Ext Lighting	Fluor	1.4%
Wholesale Trade	Ext Lighting	Incand.	0.4%
Wholesale Trade	Refrigeration	Compressors	10.0%
Wholesale Trade	Refrigeration	Fans/Motors	10.0%
Wholesale Trade	Refrigeration	Other	10.0%
Wholesale Trade	Office Equip	CPUs	1.4%
Wholesale Trade	Office Equip	Monitors	0.6%
Wholesale Trade	Office Equip	Copy/Fax	0.7%
Wholesale Trade	Office Equip	Other	10.0%
Wholesale Trade	Water	All	10.0%
Wholesale Trade	Cooking	All	10.0%
Wholesale Trade	Misc	Technology 1	10.0%
Wholesale Trade	Misc	Technology 2	10.0%
Wholesale Trade	Misc	Technology 3	10.0%
Offices	Heating	Cntrl - HP	1.1%
Offices	Heating	Cntrl - RTU/Furn	1.1%
Offices	Heating	Unitary	0.8%
Offices	Ventilation	Motor	3.5%
Offices	Ventilation	Motor w/VFD	4.3%
Offices	Cooling	Chillers	1.2%
Offices	Cooling	DX Units	4.3%
Offices	Cooling	Room AC	2.6%
Offices	Int. Lighting	4' Fluor	1.1%
Offices	Int. Lighting	8' Fluor	1.3%
Offices	Int. Lighting	Incand.	0.3%
Offices	Int. Lighting	Exit Signs	0.5%
Offices	Ext Lighting	HID	0.5%
Offices	Ext Lighting	Fluor	1.4%
Offices	Ext Lighting	Incand.	0.4%
Offices	Refrigeration	Compressors	10.0%
Offices	Refrigeration	Fans/Motors	10.0%
Offices	Refrigeration	Other	10.0%
Offices	Office Equip	CPUs	1.4%
Offices	Office Equip	Monitors	0.6%
Offices	Office Equip	Copy/Fax	0.7%
Offices	Office Equip	Other	10.0%
Offices	Water	All	10.0%
Offices	Cooking	All	10.0%
Offices	Misc	Technology 1	10.0%
Offices	Misc	Technology 2	10.0%
Offices	Misc	Technology 3	10.0%
Retail Trade	Heating	Cntrl - HP	1.1%
Retail Trade	Heating	Cntrl - RTU/Furn	1.1%
Retail Trade	Heating	Unitary	0.8%
Retail Trade	Ventilation	Motor	3.5%

Commercial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Retail Trade	Ventilation	Motor w/VFD	4.3%
Retail Trade	Cooling	Chillers	1.2%
Retail Trade	Cooling	DX Units	4.3%
Retail Trade	Cooling	Room AC	2.6%
Retail Trade	Int. Lighting	4' Fluor	1.1%
Retail Trade	Int. Lighting	8' Fluor	1.3%
Retail Trade	Int. Lighting	Incand.	0.3%
Retail Trade	Int. Lighting	Exit Signs	0.5%
Retail Trade	Ext Lighting	HID	0.5%
Retail Trade	Ext Lighting	Fluor	1.4%
Retail Trade	Ext Lighting	Incand.	0.4%
Retail Trade	Refrigeration	Compressors	10.0%
Retail Trade	Refrigeration	Fans/Motors	10.0%
Retail Trade	Refrigeration	Other	10.0%
Retail Trade	Office Equip	CPUs	1.4%
Retail Trade	Office Equip	Monitors	0.6%
Retail Trade	Office Equip	Copy/Fax	0.7%
Retail Trade	Office Equip	Other	10.0%
Retail Trade	Water	All	10.0%
Retail Trade	Cooking	All	10.0%
Retail Trade	Misc	Technology 1	10.0%
Retail Trade	Misc	Technology 2	10.0%
Retail Trade	Misc	Technology 3	10.0%
Transportation & Warehousing	Heating	Cntrl - HP	1.1%
Transportation & Warehousing	Heating	Cntrl - RTU/Furn	1.1%
Transportation & Warehousing	Heating	Unitary	0.8%
Transportation & Warehousing	Ventilation	Motor	3.5%
Transportation & Warehousing	Ventilation	Motor w/VFD	4.3%
Transportation & Warehousing	Cooling	Chillers	1.2%
Transportation & Warehousing	Cooling	DX Units	4.3%
Transportation & Warehousing	Cooling	Room AC	2.6%
Transportation & Warehousing	Int. Lighting	4' Fluor	1.1%
Transportation & Warehousing	Int. Lighting	8' Fluor	1.3%
Transportation & Warehousing	Int. Lighting	Incand.	0.3%
Transportation & Warehousing	Int. Lighting	Exit Signs	0.5%
Transportation & Warehousing	Ext Lighting	HID	0.5%
Transportation & Warehousing	Ext Lighting	Fluor	1.4%
Transportation & Warehousing	Ext Lighting	Incand.	0.4%
Transportation & Warehousing	Refrigeration	Compressors	10.0%
Transportation & Warehousing	Refrigeration	Fans/Motors	10.0%
Transportation & Warehousing	Refrigeration	Other	10.0%
Transportation & Warehousing	Office Equip	CPUs	1.4%
Transportation & Warehousing	Office Equip	Monitors	0.6%
Transportation & Warehousing	Office Equip	Copy/Fax	0.7%
Transportation & Warehousing	Office Equip	Other	10.0%
Transportation & Warehousing	Water	All	10.0%
Transportation & Warehousing	Cooking	All	10.0%
Transportation & Warehousing	Misc	Technology 1	10.0%

Commercial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Transportation & Warehousing	Misc	Technology 2	10.0%
Transportation & Warehousing	Misc	Technology 3	10.0%
Other Services	Heating	Cntrl - HP	1.1%
Other Services	Heating	Cntrl - RTU/Furn	1.1%
Other Services	Heating	Unitary	0.8%
Other Services	Ventilation	Motor	3.5%
Other Services	Ventilation	Motor w/VFD	4.3%
Other Services	Cooling	Chillers	1.2%
Other Services	Cooling	DX Units	4.3%
Other Services	Cooling	Room AC	2.6%
Other Services	Int. Lighting	4' Fluor	1.1%
Other Services	Int. Lighting	8' Fluor	1.3%
Other Services	Int. Lighting	Incand.	0.3%
Other Services	Int. Lighting	Exit Signs	0.5%
Other Services	Ext Lighting	HID	0.5%
Other Services	Ext Lighting	Fluor	1.4%
Other Services	Ext Lighting	Incand.	0.4%
Other Services	Refrigeration	Compressors	10.0%
Other Services	Refrigeration	Fans/Motors	10.0%
Other Services	Refrigeration	Other	10.0%
Other Services	Office Equip	CPUs	1.4%
Other Services	Office Equip	Monitors	0.6%
Other Services	Office Equip	Copy/Fax	0.7%
Other Services	Office Equip	Other	10.0%
Other Services	Water	All	10.0%
Other Services	Cooking	All	10.0%
Other Services	Misc	Technology 1	10.0%
Other Services	Misc	Technology 2	10.0%
Other Services	Misc	Technology 3	10.0%

Industrial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Pulp & Paper	HVAC	Heating	1.1%
Pulp & Paper	HVAC	Ventilation	6.7%
Pulp & Paper	HVAC	Air Conditioning	1.2%
Pulp & Paper	Process Coooling	Process Cooling	1.1%
Pulp & Paper	Process Coooling	N/A	20.0%
Pulp & Paper	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	0.6%
Pulp & Paper	Process Heating & Boiler Fuel	N/A	20.0%
Pulp & Paper	Process Heating & Boiler Fuel	N/A	20.0%
Pulp & Paper	Int. Lighting	4' Fluor	0.7%
Pulp & Paper	Int. Lighting	8' Fluor	1.2%
Pulp & Paper	Int. Lighting	Incand.	0.3%
Pulp & Paper	Int. Lighting	Exit Signs	0.3%
Pulp & Paper	Ext Lighting	HID	0.5%
Pulp & Paper	Ext Lighting	Fluor	1.4%
Pulp & Paper	Ext Lighting	Incand.	0.4%
Pulp & Paper	Other Process	Other Process	10.0%
Pulp & Paper	Other Process	N/A	10.0%
Pulp & Paper	Other Process	N/A	10.0%
Pulp & Paper	Other	Other	10.0%
Pulp & Paper	Other	N/A	10.0%
Pulp & Paper	Other	N/A	10.0%
Pulp & Paper	Other	N/A	10.0%
Pulp & Paper	Process Machine Drive	Process Machine Drive	3.3%
Pulp & Paper	Electrochecmical Process	Electrochemical Process	10.0%
Pulp & Paper	N/A	N/A	10.0%
Pulp & Paper	N/A	N/A	10.0%
Pulp & Paper	N/A	N/A	10.0%
Iron and Steel	HVAC	Heating	1.1%
Iron and Steel	HVAC	Ventilation	6.7%
Iron and Steel	HVAC	Air Conditioning	1.2%
Iron and Steel	Process Coooling	Process Cooling	1.1%
Iron and Steel	Process Coooling	N/A	20.0%
Iron and Steel	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	0.6%
Iron and Steel	Process Heating & Boiler Fuel	N/A	20.0%
Iron and Steel	Process Heating & Boiler Fuel	N/A	20.0%
Iron and Steel	Int. Lighting	4' Fluor	0.7%
Iron and Steel	Int. Lighting	8' Fluor	1.2%
Iron and Steel	Int. Lighting	Incand.	0.3%
Iron and Steel	Int. Lighting	Exit Signs	0.3%
Iron and Steel	Ext Lighting	HID	0.5%
Iron and Steel	Ext Lighting	Fluor	1.4%
Iron and Steel	Ext Lighting	Incand.	0.4%
Iron and Steel	Other Process	Other Process	10.0%
Iron and Steel	Other Process	N/A	10.0%
Iron and Steel	Other Process	N/A	10.0%
Iron and Steel	Other	Other	10.0%
Iron and Steel	Other	N/A	10.0%
Iron and Steel	Other	N/A	10.0%
Iron and Steel	Other	N/A	10.0%
Iron and Steel	Process Machine Drive	Process Machine Drive	3.3%
Iron and Steel	Electrochecmical Process	Electrochemical Process	10.0%

Industrial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Iron and Steel	N/A	N/A	10.0%
Iron and Steel	N/A	N/A	10.0%
Iron and Steel	N/A	N/A	10.0%
Petroleum Refining	HVAC	Heating	1.1%
Petroleum Refining	HVAC	Ventilation	6.7%
Petroleum Refining	HVAC	Air Conditioning	1.2%
Petroleum Refining	Process Coooling	Process Cooling	1.1%
Petroleum Refining	Process Coooling	N/A	20.0%
Petroleum Refining	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	0.6%
Petroleum Refining	Process Heating & Boiler Fuel	N/A	20.0%
Petroleum Refining	Process Heating & Boiler Fuel	N/A	20.0%
Petroleum Refining	Int. Lighting	4' Fluor	0.7%
Petroleum Refining	Int. Lighting	8' Fluor	1.2%
Petroleum Refining	Int. Lighting	Incand.	0.3%
Petroleum Refining	Int. Lighting	Exit Signs	0.3%
Petroleum Refining	Ext Lighting	HID	0.5%
Petroleum Refining	Ext Lighting	Fluor	1.4%
Petroleum Refining	Ext Lighting	Incand.	0.4%
Petroleum Refining	Other Process	Other Process	10.0%
Petroleum Refining	Other Process	N/A	10.0%
Petroleum Refining	Other Process	N/A	10.0%
Petroleum Refining	Other	Other	10.0%
Petroleum Refining	Other	N/A	10.0%
Petroleum Refining	Other	N/A	10.0%
Petroleum Refining	Other	N/A	10.0%
Petroleum Refining	Process Machine Drive	Process Machine Drive	3.3%
Petroleum Refining	Electrochecmical Process	Electrochemical Process	10.0%
Petroleum Refining	N/A	N/A	10.0%
Petroleum Refining	N/A	N/A	10.0%
Petroleum Refining	N/A	N/A	10.0%
Smelting and Refining	HVAC	Heating	1.1%
Smelting and Refining	HVAC	Ventilation	6.7%
Smelting and Refining	HVAC	Air Conditioning	1.2%
Smelting and Refining	Process Coooling	Process Cooling	1.1%
Smelting and Refining	Process Coooling	N/A	20.0%
Smelting and Refining	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	0.6%
Smelting and Refining	Process Heating & Boiler Fuel	N/A	20.0%
Smelting and Refining	Process Heating & Boiler Fuel	N/A	20.0%
Smelting and Refining	Int. Lighting	4' Fluor	0.7%
Smelting and Refining	Int. Lighting	8' Fluor	1.2%
Smelting and Refining	Int. Lighting	Incand.	0.3%
Smelting and Refining	Int. Lighting	Exit Signs	0.3%
Smelting and Refining	Ext Lighting	HID	0.5%
Smelting and Refining	Ext Lighting	Fluor	1.4%
Smelting and Refining	Ext Lighting	Incand.	0.4%
Smelting and Refining	Other Process	Other Process	10.0%
Smelting and Refining	Other Process	N/A	10.0%
Smelting and Refining	Other Process	N/A	10.0%
Smelting and Refining	Other	Other	10.0%
Smelting and Refining	Other	N/A	10.0%
Smelting and Refining	Other	N/A	10.0%

Industrial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Smelting and Refining	Other	N/A	10.0%
Smelting and Refining	Process Machine Drive	Process Machine Drive	3.3%
Smelting and Refining	Electrochecmical Process	Electrochemical Process	10.0%
Smelting and Refining	N/A	N/A	10.0%
Smelting and Refining	N/A	N/A	10.0%
Smelting and Refining	N/A	N/A	10.0%
Cement	HVAC	Heating	1.1%
Cement	HVAC	Ventilation	6.7%
Cement	HVAC	Air Conditioning	1.2%
Cement	Process Coooling	Process Cooling	1.1%
Cement	Process Coooling	N/A	20.0%
Cement	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	0.6%
Cement	Process Heating & Boiler Fuel	N/A	20.0%
Cement	Process Heating & Boiler Fuel	N/A	20.0%
Cement	Int. Lighting	4' Fluor	0.7%
Cement	Int. Lighting	8' Fluor	1.2%
Cement	Int. Lighting	Incand.	0.3%
Cement	Int. Lighting	Exit Signs	0.3%
Cement	Ext Lighting	HID	0.5%
Cement	Ext Lighting	Fluor	1.4%
Cement	Ext Lighting	Incand.	0.4%
Cement	Other Process	Other Process	10.0%
Cement	Other Process	N/A	10.0%
Cement	Other Process	N/A	10.0%
Cement	Other	Other	10.0%
Cement	Other	N/A	10.0%
Cement	Other	N/A	10.0%
Cement	Other	N/A	10.0%
Cement	Process Machine Drive	Process Machine Drive	3.3%
Cement	Electrochecmical Process	Electrochemical Process	10.0%
Cement	N/A	N/A	10.0%
Cement	N/A	N/A	10.0%
Cement	N/A	N/A	10.0%
Misc Manufacturing	HVAC	Heating	1.1%
Misc Manufacturing	HVAC	Ventilation	6.7%
Misc Manufacturing	HVAC	Air Conditioning	1.2%
Misc Manufacturing	Process Coooling	Process Cooling	1.1%
Misc Manufacturing	Process Coooling	N/A	20.0%
Misc Manufacturing	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	0.6%
Misc Manufacturing	Process Heating & Boiler Fuel	N/A	20.0%
Misc Manufacturing	Process Heating & Boiler Fuel	N/A	20.0%
Misc Manufacturing	Int. Lighting	4' Fluor	0.7%
Misc Manufacturing	Int. Lighting	8' Fluor	1.2%
Misc Manufacturing	Int. Lighting	Incand.	0.3%
Misc Manufacturing	Int. Lighting	Exit Signs	0.3%
Misc Manufacturing	Ext Lighting	HID	0.5%
Misc Manufacturing	Ext Lighting	Fluor	1.4%
Misc Manufacturing	Ext Lighting	Incand.	0.4%
Misc Manufacturing	Other Process	Other Process	10.0%
Misc Manufacturing	Other Process	N/A	10.0%
Misc Manufacturing	Other Process	N/A	10.0%

Industrial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Misc Manufacturing	Other	Other	10.0%
Misc Manufacturing	Other	N/A	10.0%
Misc Manufacturing	Other	N/A	10.0%
Misc Manufacturing	Other	N/A	10.0%
Misc Manufacturing	Process Machine Drive	Process Machine Drive	3.3%
Misc Manufacturing	Electrochecmical Process	Electrochemical Process	10.0%
Misc Manufacturing	N/A	N/A	10.0%
Misc Manufacturing	N/A	N/A	10.0%
Misc Manufacturing	N/A	N/A	10.0%
Chemicals	HVAC	Heating	1.1%
Chemicals	HVAC	Ventilation	6.7%
Chemicals	HVAC	Air Conditioning	1.2%
Chemicals	Process Coooling	Process Cooling	1.1%
Chemicals	Process Coooling	N/A	20.0%
Chemicals	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	0.6%
Chemicals	Process Heating & Boiler Fuel	N/A	20.0%
Chemicals	Process Heating & Boiler Fuel	N/A	20.0%
Chemicals	Int. Lighting	4' Fluor	0.7%
Chemicals	Int. Lighting	8' Fluor	1.2%
Chemicals	Int. Lighting	Incand.	0.3%
Chemicals	Int. Lighting	Exit Signs	0.3%
Chemicals	Ext Lighting	HID	0.5%
Chemicals	Ext Lighting	Fluor	1.4%
Chemicals	Ext Lighting	Incand.	0.4%
Chemicals	Other Process	Other Process	10.0%
Chemicals	Other Process	N/A	10.0%
Chemicals	Other Process	N/A	10.0%
Chemicals	Other	Other	10.0%
Chemicals	Other	N/A	10.0%
Chemicals	Other	N/A	10.0%
Chemicals	Other	N/A	10.0%
Chemicals	Process Machine Drive	Process Machine Drive	3.3%
Chemicals	Electrochecmical Process	Electrochemical Process	10.0%
Chemicals	N/A	N/A	10.0%
Chemicals	N/A	N/A	10.0%
Chemicals	N/A	N/A	10.0%
Mining	HVAC	Heating	1.1%
Mining	HVAC	Ventilation	6.7%
Mining	HVAC	Air Conditioning	1.2%
Mining	Process Coooling	Process Cooling	1.1%
Mining	Process Coooling	N/A	20.0%
Mining	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	0.6%
Mining	Process Heating & Boiler Fuel	N/A	20.0%
Mining	Process Heating & Boiler Fuel	N/A	20.0%
Mining	Int. Lighting	4' Fluor	0.7%
Mining	Int. Lighting	8' Fluor	1.2%
Mining	Int. Lighting	Incand.	0.3%
Mining	Int. Lighting	Exit Signs	0.3%
Mining	Ext Lighting	HID	0.5%
Mining	Ext Lighting	Fluor	1.4%
Mining	Ext Lighting	Incand.	0.4%

Industrial Initial Market Shares

Subsector	End Use	Technology Type	Initial Market Share
Mining	Other Process	Other Process	10.0%
Mining	Other Process	N/A	10.0%
Mining	Other Process	N/A	10.0%
Mining	Other	Other	10.0%
Mining	Other	N/A	10.0%
Mining	Other	N/A	10.0%
Mining	Other	N/A	10.0%
Mining	Process Machine Drive	Process Machine Drive	3.3%
Mining	Electrochecmical Process	Electrochemical Process	10.0%
Mining	N/A	N/A	10.0%
Mining	N/A	N/A	10.0%
Mining	N/A	N/A	10.0%

Appendix D

Technology Type and Efficiency Segmentation

Residential Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
All	Space Heat (Elec)	Central Forced Air (Elec)	24.6%	24.6%
		Existing	0.0%	0.0%
		Base	19.2%	17.6%
		Hi-Eff	5.4%	7.0%
All	Space Heat (Elec)	Electric Baseboard (Elec)	24.6%	24.6%
		Existing	0.0%	0.0%
		Base	20.3%	19.7%
		Hi-Eff	4.3%	4.9%
All	Space Heat (Elec)	Hot Water Radiator (Elec)	24.6%	24.6%
		Existing	0.0%	0.0%
		Base	20.3%	19.7%
		Hi-Eff	4.3%	4.9%
All	Space Heat (Elec)	Heat Pump (Elec)	26.1%	26.1%
		Existing	21.8%	0.0%
		Base	4.3%	26.1%
		Hi-Eff	0.0%	0.0%
All	Supp. Space Heat (Elec)	Supplemental Heater (Elec)	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%
All	Furnace Fan	Furnace Fan	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	82.1%	80.0%
		Hi-Eff	17.9%	20.0%
All	Central A/C	Central Air Conditioner	97.1%	97.1%
		Existing	81.0%	81.2%
		Base	14.9%	14.6%
		Hi-Eff	1.2%	1.3%
All	Central A/C	Heat Pump	2.9%	2.9%
		Existing	2.4%	2.4%
		Base	0.4%	0.4%
		Hi-Eff	0.0%	0.0%
All	Room A/C	Room Air Conditioner	100.0%	100.0%
		Existing	54.7%	54.7%
		Base	45.1%	45.1%
		Hi-Eff	0.2%	0.2%
All	Lights	Incandescent	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	99.1%	99.1%
		Hi-Eff	0.9%	0.9%
All	Refrigerator	Refrigerator	100.0%	100.0%
		Existing	38.0%	38.0%
		Base	44.3%	44.3%
		Hi-Eff	17.7%	17.7%
All	Freezer	Freezer	100.0%	100.0%
		Existing	33.3%	33.3%
		Base	47.7%	47.7%
		Hi-Eff	19.1%	19.1%
All	Dishwasher	Dishwasher	100.0%	100.0%
		Existing	33.0%	33.0%
		Base	47.9%	47.9%
		Hi-Eff	19.1%	19.1%

Residential Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
All	Water Heat (Elec)	Water Heater (Elec)	100.0%	100.0%
		Existing	32.7%	32.7%
		Base	51.9%	51.9%
		Hi-Eff	15.4%	15.4%
All	Clothes Dryer (Elec)	Clothes Dryer (Elec)	100.0%	100.0%
		Existing	31.1%	31.1%
		Base	49.2%	49.2%
		Hi-Eff	19.7%	19.7%
All	ClothesWash	Clothes Washer	100.0%	100.0%
		Existing	49.3%	49.3%
		Base	38.6%	38.6%
		Hi-Eff	12.2%	12.2%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Educational Services	Heating	Cntrl - HP	25.0%	25.0%
		Existing	0.0%	0.0%
		Base	19.7%	18.7%
		Hi-Eff	5.3%	6.3%
Educational Services	Heating	Cntrl - RTU/Furn	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Educational Services	Heating	Unitary	75.0%	75.0%
		Existing	0.0%	0.0%
		Base	75.0%	75.0%
		Hi-Eff	0.0%	0.0%
Educational Services	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Educational Services	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Educational Services	Cooling	Chillers	48.8%	48.8%
		Existing	17.0%	16.8%
		Base	25.3%	25.0%
		Hi-Eff	6.5%	7.0%
Educational Services	Cooling	DX Units	19.8%	19.8%
		Existing	6.8%	6.8%
		Base	10.0%	10.1%
		Hi-Eff	2.9%	2.8%
Educational Services	Cooling	Room AC	31.4%	31.4%
		Existing	0.0%	0.0%
		Base	23.5%	23.7%
		Hi-Eff	7.9%	7.7%
Educational Services	Int. Lighting	4' Fluor	80.1%	80.1%
		Existing	19.6%	19.6%
		Base	67.6%	67.6%
		Hi-Eff	12.8%	12.8%
Educational Services	Int. Lighting	8' Fluor	4.7%	4.7%
		Existing	21.1%	21.0%
		Base	67.4%	67.0%
		Hi-Eff	11.6%	12.0%
Educational Services	Int. Lighting	Incand.	3.2%	3.2%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Educational Services	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	4.1%	4.1%
		Hi-Eff	95.9%	95.9%
Educational Services	Ext Lighting	HID	64.6%	64.2%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Educational Services	Ext Lighting	Fluor	17.1%	17.2%
		Existing	19.7%	20.2%
		Base	68.0%	69.7%
		Hi-Eff	12.3%	10.1%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Educational Services	Ext Lighting	Incand.	18.4%	18.6%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Educational Services	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Educational Services	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Educational Services	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Educational Services	Office Equip	CPUs	45.0%	45.0%
		Existing	0.0%	0.0%
		Base	38.2%	36.7%
		Hi-Eff	6.8%	8.3%
Educational Services	Office Equip	Monitors	49.0%	49.0%
		Existing	0.0%	0.0%
		Base	43.7%	40.7%
		Hi-Eff	5.3%	8.3%
Educational Services	Office Equip	Copy/Fax	6.0%	6.0%
		Existing	0.0%	0.0%
		Base	5.3%	5.0%
		Hi-Eff	0.7%	1.0%
Educational Services	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Educational Services	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Arts, Entertainment and Recreation	Heating	Cntrl - HP	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Arts, Entertainment and Recreation	Heating	Cntrl - RTU/Furn	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.7%	82.7%
		Hi-Eff	14.3%	17.3%
Arts, Entertainment and Recreation	Heating	Unitary	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Arts, Entertainment and Recreation	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Arts, Entertainment and Recreation	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Arts, Entertainment and Recreation	Cooling	Chillers	22.9%	22.9%
		Existing	8.0%	7.9%
		Base	11.9%	11.7%
		Hi-Eff	3.0%	3.3%
Arts, Entertainment and Recreation	Cooling	DX Units	43.4%	43.4%
		Existing	15.0%	15.0%
		Base	22.0%	22.1%
		Hi-Eff	6.4%	6.2%
Arts, Entertainment and Recreation	Cooling	Room AC	33.7%	33.7%
		Existing	0.0%	0.0%
		Base	25.3%	25.4%
		Hi-Eff	8.5%	8.3%
Arts, Entertainment and Recreation	Int. Lighting	4' Fluor	77.2%	77.2%
		Existing	19.6%	19.6%
		Base	67.6%	67.6%
		Hi-Eff	12.8%	12.8%
Arts, Entertainment and Recreation	Int. Lighting	8' Fluor	8.0%	8.0%
		Existing	21.1%	21.1%
		Base	67.4%	67.4%
		Hi-Eff	11.5%	11.5%
Arts, Entertainment and Recreation	Int. Lighting	Incand.	3.0%	3.0%
		Existing	0.0%	0.0%
		Base	72.9%	72.9%
		Hi-Eff	27.1%	27.1%
Arts, Entertainment and Recreation	Int. Lighting	Exit Signs	11.8%	11.8%
		Existing	0.0%	0.0%
		Base	4.1%	4.1%
		Hi-Eff	95.9%	95.9%
Arts, Entertainment and Recreation	Ext Lighting	HID	68.3%	67.9%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Arts, Entertainment and Recreation	Ext Lighting	Fluor	4.6%	4.7%
		Existing	19.7%	20.2%
		Base	68.0%	69.7%
		Hi-Eff	12.3%	10.1%
Arts, Entertainment and Recreation	Ext Lighting	Incand.	27.1%	27.4%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Arts, Entertainment and Recreation	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Arts, Entertainment and Recreation	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Arts, Entertainment and Recreation	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Arts, Entertainment and Recreation	Office Equip	CPUs	45.0%	45.0%
		Existing	0.0%	0.0%
		Base	38.2%	36.7%
		Hi-Eff	6.8%	8.3%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Arts, Entertainment and Recreation	Office Equip	Monitors	49.0%	49.0%
		Existing	0.0%	0.0%
		Base	43.7%	40.7%
		Hi-Eff	5.3%	8.3%
Arts, Entertainment and Recreation	Office Equip	Copy/Fax	6.0%	6.0%
		Existing	0.0%	0.0%
		Base	5.3%	5.0%
		Hi-Eff	0.7%	1.0%
Arts, Entertainment and Recreation	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Arts, Entertainment and Recreation	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Information & Cultural Industries	Heating	Cntrl - HP	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Information & Cultural Industries	Heating	Cntrl - RTU/Furn	75.3%	75.3%
		Existing	0.0%	0.0%
		Base	64.6%	62.3%
		Hi-Eff	10.7%	13.0%
Information & Cultural Industries	Heating	Unitary	24.7%	24.7%
		Existing	0.0%	0.0%
		Base	24.7%	24.7%
		Hi-Eff	0.0%	0.0%
Information & Cultural Industries	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Information & Cultural Industries	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Information & Cultural Industries	Cooling	Chillers	9.1%	9.1%
		Existing	3.2%	3.1%
		Base	4.7%	4.7%
		Hi-Eff	1.2%	1.3%
Information & Cultural Industries	Cooling	DX Units	67.5%	67.5%
		Existing	23.3%	23.4%
		Base	34.3%	34.4%
		Hi-Eff	9.9%	9.7%
Information & Cultural Industries	Cooling	Room AC	23.4%	23.4%
		Existing	0.0%	0.0%
		Base	17.5%	17.6%
		Hi-Eff	5.9%	5.7%
Information & Cultural Industries	Int. Lighting	4' Fluor	29.2%	29.2%
		Existing	49.7%	49.7%
		Base	43.3%	43.3%
		Hi-Eff	7.0%	7.0%
Information & Cultural Industries	Int. Lighting	8' Fluor	62.3%	62.4%
		Existing	52.0%	51.8%
		Base	41.9%	41.8%
		Hi-Eff	6.1%	6.4%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Information & Cultural Industries	Int. Lighting	Incand.	0.8%	0.8%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Information & Cultural Industries	Int. Lighting	Exit Signs	7.6%	7.6%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Information & Cultural Industries	Ext Lighting	HID	58.1%	57.7%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Information & Cultural Industries	Ext Lighting	Fluor	26.0%	26.3%
		Existing	49.8%	50.5%
		Base	43.4%	44.1%
		Hi-Eff	6.7%	5.4%
Information & Cultural Industries	Ext Lighting	Incand.	15.9%	16.0%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Information & Cultural Industries	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Information & Cultural Industries	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Information & Cultural Industries	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Information & Cultural Industries	Office Equip	CPUs	26.3%	26.3%
		Existing	0.0%	0.0%
		Base	22.3%	21.4%
		Hi-Eff	4.0%	4.8%
Information & Cultural Industries	Office Equip	Monitors	42.4%	42.4%
		Existing	0.0%	0.0%
		Base	37.8%	35.2%
		Hi-Eff	4.6%	7.2%
Information & Cultural Industries	Office Equip	Copy/Fax	31.3%	31.3%
		Existing	0.0%	0.0%
		Base	27.5%	25.9%
		Hi-Eff	3.8%	5.5%
Information & Cultural Industries	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Information & Cultural Industries	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Accommodation & Food Services	Heating	Cntrl - HP	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Accommodation & Food Services	Heating	Cntrl - RTU/Furn	99.5%	99.5%
		Existing	0.0%	0.0%
		Base	85.3%	82.3%
		Hi-Eff	14.2%	17.2%
Accommodation & Food Services	Heating	Unitary	0.5%	0.5%
		Existing	0.0%	0.0%
		Base	0.5%	0.5%
		Hi-Eff	0.0%	0.0%
Accommodation & Food Services	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Accommodation & Food Services	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Accommodation & Food Services	Cooling	Chillers	9.0%	9.0%
		Existing	3.1%	3.1%
		Base	4.7%	4.6%
		Hi-Eff	1.2%	1.3%
Accommodation & Food Services	Cooling	DX Units	57.3%	57.3%
		Existing	19.8%	19.9%
		Base	29.1%	29.2%
		Hi-Eff	8.4%	8.2%
Accommodation & Food Services	Cooling	Room AC	33.7%	33.7%
		Existing	0.0%	0.0%
		Base	25.3%	25.4%
		Hi-Eff	8.5%	8.3%
Accommodation & Food Services	Int. Lighting	4' Fluor	64.3%	64.3%
		Existing	51.7%	51.7%
		Base	41.3%	41.3%
		Hi-Eff	7.0%	7.0%
Accommodation & Food Services	Int. Lighting	8' Fluor	16.2%	16.2%
		Existing	54.0%	53.8%
		Base	39.9%	39.8%
		Hi-Eff	6.1%	6.4%
Accommodation & Food Services	Int. Lighting	Incand.	12.5%	12.5%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Accommodation & Food Services	Int. Lighting	Exit Signs	7.0%	7.0%
		Existing	0.0%	0.0%
		Base	14.5%	14.5%
		Hi-Eff	85.5%	85.5%
Accommodation & Food Services	Ext Lighting	HID	50.4%	50.0%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Accommodation & Food Services	Ext Lighting	Fluor	19.4%	19.6%
		Existing	51.8%	52.5%
		Base	41.4%	42.0%
		Hi-Eff	6.7%	5.4%
Accommodation & Food Services	Ext Lighting	Incand.	30.2%	30.4%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Accommodation & Food Services	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Accommodation & Food Services	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Accommodation & Food Services	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Accommodation & Food Services	Office Equip	CPUs	35.0%	35.0%
		Existing	0.0%	0.0%
		Base	29.7%	28.6%
		Hi-Eff	5.3%	6.4%
Accommodation & Food Services	Office Equip	Monitors	44.0%	44.0%
		Existing	0.0%	0.0%
		Base	39.2%	36.5%
		Hi-Eff	4.8%	7.5%
Accommodation & Food Services	Office Equip	Copy/Fax	21.0%	21.0%
		Existing	0.0%	0.0%
		Base	18.5%	17.3%
		Hi-Eff	2.5%	3.7%
Accommodation & Food Services	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Accommodation & Food Services	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Health Care & Social Assistance	Heating	Cntrl - HP	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Health Care & Social Assistance	Heating	Cntrl - RTU/Furn	61.9%	61.9%
		Existing	0.0%	0.0%
		Base	53.1%	51.2%
		Hi-Eff	8.8%	10.7%
Health Care & Social Assistance	Heating	Unitary	38.1%	38.1%
		Existing	0.0%	0.0%
		Base	38.1%	38.1%
		Hi-Eff	0.0%	0.0%
Health Care & Social Assistance	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Health Care & Social Assistance	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Health Care & Social Assistance	Cooling	Chillers	27.4%	27.4%
		Existing	9.6%	9.4%
		Base	14.2%	14.0%
		Hi-Eff	3.6%	3.9%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Health Care & Social Assistance	Cooling	DX Units	50.7%	50.7%
		Existing	17.5%	17.6%
		Base	25.7%	25.8%
		Hi-Eff	7.5%	7.3%
Health Care & Social Assistance	Cooling	Room AC	21.9%	21.9%
		Existing	0.0%	0.0%
		Base	16.4%	16.5%
		Hi-Eff	5.5%	5.4%
Health Care & Social Assistance	Int. Lighting	4' Fluor	89.6%	89.6%
		Existing	24.9%	24.9%
		Base	63.7%	63.7%
		Hi-Eff	11.4%	11.4%
Health Care & Social Assistance	Int. Lighting	8' Fluor	1.8%	1.8%
		Existing	26.6%	26.5%
		Base	63.1%	62.9%
		Hi-Eff	10.2%	10.6%
Health Care & Social Assistance	Int. Lighting	Incand.	2.2%	2.2%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Health Care & Social Assistance	Int. Lighting	Exit Signs	6.4%	6.4%
		Existing	0.0%	0.0%
		Base	13.0%	13.0%
		Hi-Eff	87.0%	87.0%
Health Care & Social Assistance	Ext Lighting	HID	42.3%	41.9%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Health Care & Social Assistance	Ext Lighting	Fluor	18.1%	18.2%
		Existing	25.0%	25.6%
		Base	64.0%	65.5%
		Hi-Eff	11.0%	8.9%
Health Care & Social Assistance	Ext Lighting	Incand.	39.6%	39.9%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Health Care & Social Assistance	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Health Care & Social Assistance	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Health Care & Social Assistance	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Health Care & Social Assistance	Office Equip	CPUs	31.0%	31.0%
		Existing	0.0%	0.0%
		Base	26.3%	25.3%
		Hi-Eff	4.7%	5.7%
Health Care & Social Assistance	Office Equip	Monitors	53.0%	53.0%
		Existing	0.0%	0.0%
		Base	47.2%	44.0%
		Hi-Eff	5.8%	9.0%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Health Care & Social Assistance	Office Equip	Copy/Fax	16.0%	16.0%
		Existing	0.0%	0.0%
		Base	14.1%	13.2%
		Hi-Eff	1.9%	2.8%
Health Care & Social Assistance	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Health Care & Social Assistance	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Wholesale Trade	Heating	Cntrl - HP	7.7%	7.7%
		Existing	0.0%	0.0%
		Base	6.1%	5.8%
		Hi-Eff	1.6%	1.9%
Wholesale Trade	Heating	Cntrl - RTU/Furn	2.0%	2.0%
		Existing	0.0%	0.0%
		Base	1.7%	1.7%
		Hi-Eff	0.3%	0.3%
Wholesale Trade	Heating	Unitary	90.3%	90.3%
		Existing	0.0%	0.0%
		Base	90.3%	90.3%
		Hi-Eff	0.0%	0.0%
Wholesale Trade	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Wholesale Trade	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Wholesale Trade	Cooling	Chillers	15.1%	15.1%
		Existing	5.2%	5.2%
		Base	7.8%	7.7%
		Hi-Eff	2.0%	2.2%
Wholesale Trade	Cooling	DX Units	26.9%	26.9%
		Existing	9.3%	9.3%
		Base	13.6%	13.7%
		Hi-Eff	4.0%	3.9%
Wholesale Trade	Cooling	Room AC	58.1%	58.1%
		Existing	0.0%	0.0%
		Base	43.5%	43.8%
		Hi-Eff	14.6%	14.3%
Wholesale Trade	Int. Lighting	4' Fluor	72.6%	72.6%
		Existing	33.1%	33.1%
		Base	56.9%	56.9%
		Hi-Eff	10.0%	10.0%
Wholesale Trade	Int. Lighting	8' Fluor	5.2%	5.3%
		Existing	35.2%	35.0%
		Base	55.9%	55.7%
		Hi-Eff	8.9%	9.3%
Wholesale Trade	Int. Lighting	Incand.	14.5%	14.5%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Wholesale Trade	Int. Lighting	Exit Signs	7.7%	7.7%
		Existing	0.0%	0.0%
		Base	10.1%	10.1%
		Hi-Eff	89.9%	89.9%
Wholesale Trade	Ext Lighting	HID	52.4%	52.0%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Wholesale Trade	Ext Lighting	Fluor	16.0%	16.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Wholesale Trade	Ext Lighting	Incand.	31.6%	31.9%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Wholesale Trade	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Wholesale Trade	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Wholesale Trade	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Wholesale Trade	Office Equip	CPUs	34.0%	34.0%
		Existing	0.0%	0.0%
		Base	28.9%	27.8%
		Hi-Eff	5.1%	6.2%
Wholesale Trade	Office Equip	Monitors	44.0%	44.0%
		Existing	0.0%	0.0%
		Base	39.2%	36.5%
		Hi-Eff	4.8%	7.5%
Wholesale Trade	Office Equip	Copy/Fax	22.0%	22.0%
		Existing	0.0%	0.0%
		Base	19.3%	18.2%
		Hi-Eff	2.7%	3.8%
Wholesale Trade	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Wholesale Trade	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Offices	Heating	Cntrl - HP	7.7%	7.7%
		Existing	0.0%	0.0%
		Base	6.1%	5.8%
		Hi-Eff	1.6%	1.9%
Offices	Heating	Cntrl - RTU/Furn	57.1%	57.1%
		Existing	0.0%	0.0%
		Base	49.0%	47.2%
		Hi-Eff	8.1%	9.9%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Offices	Heating	Unitary	35.2%	35.2%
		Existing	0.0%	0.0%
		Base	35.2%	35.2%
		Hi-Eff	0.0%	0.0%
Offices	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Offices	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Offices	Cooling	Chillers	32.5%	32.5%
		Existing	11.3%	11.2%
		Base	16.9%	16.6%
		Hi-Eff	4.3%	4.7%
Offices	Cooling	DX Units	62.5%	62.5%
		Existing	21.6%	21.7%
		Base	31.7%	31.8%
		Hi-Eff	9.2%	9.0%
Offices	Cooling	Room AC	5.0%	5.0%
		Existing	0.0%	0.0%
		Base	3.7%	3.8%
		Hi-Eff	1.3%	1.2%
Offices	Int. Lighting	4' Fluor	81.5%	81.5%
		Existing	33.1%	33.1%
		Base	56.9%	56.9%
		Hi-Eff	10.0%	10.0%
Offices	Int. Lighting	8' Fluor	8.7%	8.7%
		Existing	35.2%	35.0%
		Base	55.9%	55.7%
		Hi-Eff	8.9%	9.3%
Offices	Int. Lighting	Incand.	2.3%	2.3%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Offices	Int. Lighting	Exit Signs	7.5%	7.5%
		Existing	0.0%	0.0%
		Base	10.1%	10.1%
		Hi-Eff	89.9%	89.9%
Offices	Ext Lighting	HID	65.6%	65.3%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Offices	Ext Lighting	Fluor	18.7%	18.9%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Offices	Ext Lighting	Incand.	15.6%	15.8%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Offices	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Offices	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Offices	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Offices	Office Equip	CPUs	37.6%	37.6%
		Existing	0.0%	0.0%
		Base	31.9%	30.7%
		Hi-Eff	5.7%	6.9%
Offices	Office Equip	Monitors	46.5%	46.5%
		Existing	0.0%	0.0%
		Base	41.5%	38.6%
		Hi-Eff	5.1%	7.9%
Offices	Office Equip	Copy/Fax	15.8%	15.8%
		Existing	0.0%	0.0%
		Base	13.9%	13.1%
		Hi-Eff	1.9%	2.8%
Offices	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Offices	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Retail Trade	Heating	Cntrl - HP	5.1%	5.1%
		Existing	0.0%	0.0%
		Base	4.0%	3.8%
		Hi-Eff	1.1%	1.3%
Retail Trade	Heating	Cntrl - RTU/Furn	52.5%	52.5%
		Existing	0.0%	0.0%
		Base	45.0%	43.5%
		Hi-Eff	7.5%	9.1%
Retail Trade	Heating	Unitary	42.4%	42.4%
		Existing	0.0%	0.0%
		Base	42.4%	42.4%
		Hi-Eff	0.0%	0.0%
Retail Trade	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Retail Trade	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Retail Trade	Cooling	Chillers	8.4%	8.4%
		Existing	2.9%	2.9%
		Base	4.4%	4.3%
		Hi-Eff	1.1%	1.2%
Retail Trade	Cooling	DX Units	15.7%	15.7%
		Existing	5.4%	5.4%
		Base	8.0%	8.0%
		Hi-Eff	2.3%	2.3%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Retail Trade	Cooling	Room AC	75.9%	75.9%
		Existing	0.0%	0.0%
		Base	56.9%	57.3%
		Hi-Eff	19.0%	18.7%
Retail Trade	Int. Lighting	4' Fluor	67.9%	67.9%
		Existing	33.1%	33.1%
		Base	56.9%	56.9%
		Hi-Eff	10.0%	10.0%
Retail Trade	Int. Lighting	8' Fluor	18.0%	18.0%
		Existing	35.2%	35.0%
		Base	55.9%	55.7%
		Hi-Eff	8.9%	9.3%
Retail Trade	Int. Lighting	Incand.	5.9%	5.9%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Retail Trade	Int. Lighting	Exit Signs	8.2%	8.2%
		Existing	0.0%	0.0%
		Base	10.1%	10.1%
		Hi-Eff	89.9%	89.9%
Retail Trade	Ext Lighting	HID	52.4%	52.0%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Retail Trade	Ext Lighting	Fluor	31.3%	31.5%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Retail Trade	Ext Lighting	Incand.	16.3%	16.5%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Retail Trade	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Retail Trade	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Retail Trade	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Retail Trade	Office Equip	CPUs	37.0%	37.0%
		Existing	0.0%	0.0%
		Base	31.4%	30.2%
		Hi-Eff	5.6%	6.8%
Retail Trade	Office Equip	Monitors	48.0%	48.0%
		Existing	0.0%	0.0%
		Base	42.8%	39.8%
		Hi-Eff	5.2%	8.2%
Retail Trade	Office Equip	Copy/Fax	15.0%	15.0%
		Existing	0.0%	0.0%
		Base	13.2%	12.4%
		Hi-Eff	1.8%	2.6%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Retail Trade	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Retail Trade	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Transportation & Warehousing	Heating	Cntrl - HP	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Transportation & Warehousing	Heating	Cntrl - RTU/Furn	84.2%	84.2%
		Existing	0.0%	0.0%
		Base	72.2%	69.7%
		Hi-Eff	12.0%	14.5%
Transportation & Warehousing	Heating	Unitary	15.8%	15.8%
		Existing	0.0%	0.0%
		Base	15.8%	15.8%
		Hi-Eff	0.0%	0.0%
Transportation & Warehousing	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Transportation & Warehousing	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Transportation & Warehousing	Cooling	Chillers	14.5%	14.5%
		Existing	5.0%	5.0%
		Base	7.5%	7.4%
		Hi-Eff	1.9%	2.1%
Transportation & Warehousing	Cooling	DX Units	56.6%	56.6%
		Existing	19.5%	19.6%
		Base	28.7%	28.8%
		Hi-Eff	8.3%	8.1%
Transportation & Warehousing	Cooling	Room AC	28.9%	28.9%
		Existing	0.0%	0.0%
		Base	21.7%	21.8%
		Hi-Eff	7.3%	7.1%
Transportation & Warehousing	Int. Lighting	4' Fluor	49.5%	49.5%
		Existing	33.1%	33.1%
		Base	56.9%	56.9%
		Hi-Eff	10.0%	10.0%
Transportation & Warehousing	Int. Lighting	8' Fluor	38.7%	38.8%
		Existing	35.2%	35.0%
		Base	55.9%	55.7%
		Hi-Eff	8.9%	9.3%
Transportation & Warehousing	Int. Lighting	Incand.	3.4%	3.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Transportation & Warehousing	Int. Lighting	Exit Signs	8.4%	8.4%
		Existing	0.0%	0.0%
		Base	10.1%	10.1%
		Hi-Eff	89.9%	89.9%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Transportation & Warehousing	Ext Lighting	HID	57.1%	56.7%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Transportation & Warehousing	Ext Lighting	Fluor	23.1%	23.3%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Transportation & Warehousing	Ext Lighting	Incand.	19.8%	20.0%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Transportation & Warehousing	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Transportation & Warehousing	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%
Transportation & Warehousing	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Transportation & Warehousing	Office Equip	CPUs	31.7%	31.7%
		Existing	0.0%	0.0%
		Base	26.9%	25.9%
		Hi-Eff	4.8%	5.8%
Transportation & Warehousing	Office Equip	Monitors	42.6%	42.6%
		Existing	0.0%	0.0%
		Base	37.9%	35.3%
		Hi-Eff	4.6%	7.3%
Transportation & Warehousing	Office Equip	Copy/Fax	25.7%	25.7%
		Existing	0.0%	0.0%
		Base	22.6%	21.3%
		Hi-Eff	3.1%	4.5%
Transportation & Warehousing	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Transportation & Warehousing	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Other Services	Heating	Cntrl - HP	13.1%	13.1%
		Existing	0.0%	0.0%
		Base	10.3%	9.8%
		Hi-Eff	2.8%	3.3%
Other Services	Heating	Cntrl - RTU/Furn	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Other Services	Heating	Unitary	86.9%	86.9%
		Existing	0.0%	0.0%
		Base	86.9%	86.9%
		Hi-Eff	0.0%	0.0%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Other Services	Ventilation	Motor	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	42.3%	41.2%
		Hi-Eff	7.7%	8.8%
Other Services	Ventilation	Motor w/VFD	50.0%	50.0%
		Existing	0.0%	0.0%
		Base	41.9%	41.2%
		Hi-Eff	8.1%	8.8%
Other Services	Cooling	Chillers	20.7%	20.7%
		Existing	7.2%	7.1%
		Base	10.7%	10.6%
		Hi-Eff	2.7%	3.0%
Other Services	Cooling	DX Units	46.7%	46.7%
		Existing	16.1%	16.2%
		Base	23.7%	23.8%
		Hi-Eff	6.9%	6.7%
Other Services	Cooling	Room AC	32.6%	32.6%
		Existing	0.0%	0.0%
		Base	24.4%	24.6%
		Hi-Eff	8.2%	8.0%
Other Services	Int. Lighting	4' Fluor	34.5%	34.5%
		Existing	33.1%	33.1%
		Base	56.9%	56.9%
		Hi-Eff	10.0%	10.0%
Other Services	Int. Lighting	8' Fluor	47.3%	47.3%
		Existing	35.2%	35.0%
		Base	55.9%	55.7%
		Hi-Eff	8.9%	9.3%
Other Services	Int. Lighting	Incand.	4.3%	4.3%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Other Services	Int. Lighting	Exit Signs	13.9%	13.9%
		Existing	0.0%	0.0%
		Base	10.1%	10.1%
		Hi-Eff	89.9%	89.9%
Other Services	Ext Lighting	HID	70.2%	69.9%
		Existing	0.0%	0.0%
		Base	63.6%	68.7%
		Hi-Eff	36.4%	31.3%
Other Services	Ext Lighting	Fluor	16.9%	17.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Other Services	Ext Lighting	Incand.	12.9%	13.0%
		Existing	0.0%	0.0%
		Base	80.6%	83.9%
		Hi-Eff	19.4%	16.1%
Other Services	Refrigeration	Compressors	70.0%	70.0%
		Existing	0.0%	0.0%
		Base	56.0%	56.0%
		Hi-Eff	14.0%	14.0%
Other Services	Refrigeration	Fans/Motors	30.0%	30.0%
		Existing	0.0%	0.0%
		Base	24.0%	24.0%
		Hi-Eff	6.0%	6.0%

Commercial Technology Type and Efficiency Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Other Services	Refrigeration	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Other Services	Office Equip	CPUs	33.0%	33.0%
		Existing	0.0%	0.0%
		Base	28.0%	26.9%
		Hi-Eff	5.0%	6.1%
Other Services	Office Equip	Monitors	44.0%	44.0%
		Existing	0.0%	0.0%
		Base	39.2%	36.5%
		Hi-Eff	4.8%	7.5%
Other Services	Office Equip	Copy/Fax	23.0%	23.0%
		Existing	0.0%	0.0%
		Base	20.2%	19.0%
		Hi-Eff	2.8%	4.0%
Other Services	Office Equip	Other	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Other Services	Water	All	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Pulp & Paper	HVAC	Heating	15.3%	15.3%
		Existing	0.0%	0.0%
		Base	13.1%	12.7%
		Hi-Eff	2.2%	2.6%
Pulp & Paper	HVAC	Ventilation	20.9%	20.9%
		Existing	0.0%	0.0%
		Base	17.6%	17.2%
		Hi-Eff	3.3%	3.7%
Pulp & Paper	HVAC	Air Conditioning	63.8%	63.8%
		Existing	22.0%	21.5%
		Base	33.4%	32.7%
		Hi-Eff	8.4%	9.6%
Pulp & Paper	Process Coooling	Process Cooling	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.6%	85.6%
		Hi-Eff	14.4%	14.4%
Pulp & Paper	Process Coooling	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	89.0%	89.0%
		Hi-Eff	11.0%	11.0%
Pulp & Paper	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	Int. Lighting	4' Fluor	35.2%	35.1%
		Existing	38.7%	38.7%
		Base	52.0%	52.0%
		Hi-Eff	9.3%	9.3%
Pulp & Paper	Int. Lighting	8' Fluor	48.5%	48.5%
		Existing	40.9%	40.8%
		Base	50.8%	50.6%
		Hi-Eff	8.2%	8.6%
Pulp & Paper	Int. Lighting	Incand.	4.4%	4.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Pulp & Paper	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Pulp & Paper	Ext Lighting	HID	70.2%	68.6%
		Existing	0.0%	0.0%
		Base	63.6%	78.0%
		Hi-Eff	36.4%	22.0%
Pulp & Paper	Ext Lighting	Fluor	16.9%	18.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Pulp & Paper	Ext Lighting	Incand.	12.9%	13.3%
		Existing	0.0%	0.0%
		Base	80.6%	90.7%
		Hi-Eff	19.4%	9.3%
Pulp & Paper	Other Process	Other Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Pulp & Paper	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Pulp & Paper	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	Other	Other	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Pulp & Paper	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	Process Machine Drive	Process Machine Drive	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	81.9%	81.9%
		Hi-Eff	18.1%	18.1%
Pulp & Paper	Electrochecmical Process	Electrochemical Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Pulp & Paper	N/A	N/A	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Pulp & Paper	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	HVAC	Heating	15.3%	15.3%
		Existing	0.0%	0.0%
		Base	13.1%	12.7%
		Hi-Eff	2.2%	2.6%
Iron and Steel	HVAC	Ventilation	20.9%	20.9%
		Existing	0.0%	0.0%
		Base	17.6%	17.2%
		Hi-Eff	3.3%	3.7%
Iron and Steel	HVAC	Air Conditioning	63.8%	63.8%
		Existing	22.0%	21.5%
		Base	33.4%	32.7%
		Hi-Eff	8.4%	9.6%
Iron and Steel	Process Coooling	Process Cooling	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.6%	85.6%
		Hi-Eff	14.4%	14.4%
Iron and Steel	Process Coooling	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	89.0%	89.0%
		Hi-Eff	11.0%	11.0%
Iron and Steel	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Iron and Steel	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	Int. Lighting	4' Fluor	35.2%	35.1%
		Existing	38.7%	38.7%
		Base	52.0%	52.0%
		Hi-Eff	9.3%	9.3%
Iron and Steel	Int. Lighting	8' Fluor	48.5%	48.5%
		Existing	40.9%	40.8%
		Base	50.8%	50.6%
		Hi-Eff	8.2%	8.6%
Iron and Steel	Int. Lighting	Incand.	4.4%	4.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Iron and Steel	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Iron and Steel	Ext Lighting	HID	70.2%	68.6%
		Existing	0.0%	0.0%
		Base	63.6%	78.0%
		Hi-Eff	36.4%	22.0%
Iron and Steel	Ext Lighting	Fluor	16.9%	18.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Iron and Steel	Ext Lighting	Incand.	12.9%	13.3%
		Existing	0.0%	0.0%
		Base	80.6%	90.7%
		Hi-Eff	19.4%	9.3%
Iron and Steel	Other Process	Other Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Iron and Steel	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	Other	Other	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Iron and Steel	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	Process Machine Drive	Process Machine Drive	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	81.9%	81.9%
		Hi-Eff	18.1%	18.1%
Iron and Steel	Electrochecmical Process	Electrochemical Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Iron and Steel	N/A	N/A	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Iron and Steel	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	HVAC	Heating	15.3%	15.3%
		Existing	0.0%	0.0%
		Base	13.1%	12.7%
		Hi-Eff	2.2%	2.6%
Petroleum Refining	HVAC	Ventilation	20.9%	20.9%
		Existing	0.0%	0.0%
		Base	17.6%	17.2%
		Hi-Eff	3.3%	3.7%
Petroleum Refining	HVAC	Air Conditioning	63.8%	63.8%
		Existing	22.0%	21.5%
		Base	33.4%	32.7%
		Hi-Eff	8.4%	9.6%
Petroleum Refining	Process Coooling	Process Cooling	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.6%	85.6%
		Hi-Eff	14.4%	14.4%
Petroleum Refining	Process Coooling	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	89.0%	89.0%
		Hi-Eff	11.0%	11.0%
Petroleum Refining	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	Int. Lighting	4' Fluor	35.2%	35.1%
		Existing	38.7%	38.7%
		Base	52.0%	52.0%
		Hi-Eff	9.3%	9.3%
Petroleum Refining	Int. Lighting	8' Fluor	48.5%	48.5%
		Existing	40.9%	40.8%
		Base	50.8%	50.6%
		Hi-Eff	8.2%	8.6%
Petroleum Refining	Int. Lighting	Incand.	4.4%	4.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Petroleum Refining	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Petroleum Refining	Ext Lighting	HID	70.2%	68.6%
		Existing	0.0%	0.0%
		Base	63.6%	78.0%
		Hi-Eff	36.4%	22.0%
Petroleum Refining	Ext Lighting	Fluor	16.9%	18.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Petroleum Refining	Ext Lighting	Incand.	12.9%	13.3%
		Existing	0.0%	0.0%
		Base	80.6%	90.7%
		Hi-Eff	19.4%	9.3%
Petroleum Refining	Other Process	Other Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Petroleum Refining	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	Other	Other	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Petroleum Refining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	Process Machine Drive	Process Machine Drive	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	81.9%	81.9%
		Hi-Eff	18.1%	18.1%
Petroleum Refining	Electrochecmical Process	Electrochemical Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Petroleum Refining	N/A	N/A	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Petroleum Refining	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	HVAC	Heating	15.3%	15.3%
		Existing	0.0%	0.0%
		Base	13.1%	12.7%
		Hi-Eff	2.2%	2.6%
Smelting and Refining	HVAC	Ventilation	20.9%	20.9%
		Existing	0.0%	0.0%
		Base	17.6%	17.2%
		Hi-Eff	3.3%	3.7%
Smelting and Refining	HVAC	Air Conditioning	63.8%	63.8%
		Existing	22.0%	21.5%
		Base	33.4%	32.7%
		Hi-Eff	8.4%	9.6%
Smelting and Refining	Process Coooling	Process Cooling	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.6%	85.6%
		Hi-Eff	14.4%	14.4%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Smelting and Refining	Process Coooling	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	89.0%	89.0%
		Hi-Eff	11.0%	11.0%
Smelting and Refining	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	Int. Lighting	4' Fluor	35.2%	35.1%
		Existing	38.7%	38.7%
		Base	52.0%	52.0%
		Hi-Eff	9.3%	9.3%
Smelting and Refining	Int. Lighting	8' Fluor	48.5%	48.5%
		Existing	40.9%	40.8%
		Base	50.8%	50.6%
		Hi-Eff	8.2%	8.6%
Smelting and Refining	Int. Lighting	Incand.	4.4%	4.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Smelting and Refining	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Smelting and Refining	Ext Lighting	HID	70.2%	68.6%
		Existing	0.0%	0.0%
		Base	63.6%	78.0%
		Hi-Eff	36.4%	22.0%
Smelting and Refining	Ext Lighting	Fluor	16.9%	18.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Smelting and Refining	Ext Lighting	Incand.	12.9%	13.3%
		Existing	0.0%	0.0%
		Base	80.6%	90.7%
		Hi-Eff	19.4%	9.3%
Smelting and Refining	Other Process	Other Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Smelting and Refining	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	Other	Other	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Smelting and Refining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Smelting and Refining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	Process Machine Drive	Process Machine Drive	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	81.9%	81.9%
		Hi-Eff	18.1%	18.1%
Smelting and Refining	Electrochecmical Process	Electrochemical Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Smelting and Refining	N/A	N/A	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Smelting and Refining	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	HVAC	Heating	15.3%	15.3%
		Existing	0.0%	0.0%
		Base	13.1%	12.7%
		Hi-Eff	2.2%	2.6%
Cement	HVAC	Ventilation	20.9%	20.9%
		Existing	0.0%	0.0%
		Base	17.6%	17.2%
		Hi-Eff	3.3%	3.7%
Cement	HVAC	Air Conditioning	63.8%	63.8%
		Existing	22.0%	21.5%
		Base	33.4%	32.7%
		Hi-Eff	8.4%	9.6%
Cement	Process Coooling	Process Cooling	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.6%	85.6%
		Hi-Eff	14.4%	14.4%
Cement	Process Coooling	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	89.0%	89.0%
		Hi-Eff	11.0%	11.0%
Cement	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	Int. Lighting	4' Fluor	35.2%	35.1%
		Existing	38.7%	38.7%
		Base	52.0%	52.0%
		Hi-Eff	9.3%	9.3%
Cement	Int. Lighting	8' Fluor	48.5%	48.5%
		Existing	40.9%	40.8%
		Base	50.8%	50.6%
		Hi-Eff	8.2%	8.6%
Cement	Int. Lighting	Incand.	4.4%	4.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Cement	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Cement	Ext Lighting	HID	70.2%	68.6%
		Existing	0.0%	0.0%
		Base	63.6%	78.0%
		Hi-Eff	36.4%	22.0%
Cement	Ext Lighting	Fluor	16.9%	18.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Cement	Ext Lighting	Incand.	12.9%	13.3%
		Existing	0.0%	0.0%
		Base	80.6%	90.7%
		Hi-Eff	19.4%	9.3%
Cement	Other Process	Other Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Cement	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	Other	Other	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Cement	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	Process Machine Drive	Process Machine Drive	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	81.9%	81.9%
		Hi-Eff	18.1%	18.1%
Cement	Electrochecmical Process	Electrochemical Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Cement	N/A	N/A	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%
Cement	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Cement	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	HVAC	Heating	15.3%	15.3%
		Existing	0.0%	0.0%
		Base	13.1%	12.7%
		Hi-Eff	2.2%	2.6%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Misc Manufacturing	HVAC	Ventilation	20.9%	20.9%
		Existing	0.0%	0.0%
		Base	17.6%	17.2%
		Hi-Eff	3.3%	3.7%
Misc Manufacturing	HVAC	Air Conditioning	63.8%	63.8%
		Existing	22.0%	21.5%
		Base	33.4%	32.7%
		Hi-Eff	8.4%	9.6%
Misc Manufacturing	Process Coooling	Process Cooling	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.6%	85.6%
		Hi-Eff	14.4%	14.4%
Misc Manufacturing	Process Coooling	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	89.0%	89.0%
		Hi-Eff	11.0%	11.0%
Misc Manufacturing	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	Int. Lighting	4' Fluor	35.2%	35.1%
		Existing	38.7%	38.7%
		Base	52.0%	52.0%
		Hi-Eff	9.3%	9.3%
Misc Manufacturing	Int. Lighting	8' Fluor	48.5%	48.5%
		Existing	40.9%	40.8%
		Base	50.8%	50.6%
		Hi-Eff	8.2%	8.6%
Misc Manufacturing	Int. Lighting	Incand.	4.4%	4.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Misc Manufacturing	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Misc Manufacturing	Ext Lighting	HID	70.2%	68.6%
		Existing	0.0%	0.0%
		Base	63.6%	78.0%
		Hi-Eff	36.4%	22.0%
Misc Manufacturing	Ext Lighting	Fluor	16.9%	18.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Misc Manufacturing	Ext Lighting	Incand.	12.9%	13.3%
		Existing	0.0%	0.0%
		Base	80.6%	90.7%
		Hi-Eff	19.4%	9.3%
Misc Manufacturing	Other Process	Other Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Misc Manufacturing	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Misc Manufacturing	Other	Other	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Misc Manufacturing	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	Process Machine Drive	Process Machine Drive	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	81.9%	81.9%
		Hi-Eff	18.1%	18.1%
Misc Manufacturing	Electrochecmical Process	Electrochemical Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Misc Manufacturing	N/A	N/A	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Misc Manufacturing	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	HVAC	Heating	15.3%	15.3%
		Existing	0.0%	0.0%
		Base	13.1%	12.7%
		Hi-Eff	2.2%	2.6%
Chemicals	HVAC	Ventilation	20.9%	20.9%
		Existing	0.0%	0.0%
		Base	17.6%	17.2%
		Hi-Eff	3.3%	3.7%
Chemicals	HVAC	Air Conditioning	63.8%	63.8%
		Existing	22.0%	21.5%
		Base	33.4%	32.7%
		Hi-Eff	8.4%	9.6%
Chemicals	Process Coooling	Process Cooling	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.6%	85.6%
		Hi-Eff	14.4%	14.4%
Chemicals	Process Coooling	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	89.0%	89.0%
		Hi-Eff	11.0%	11.0%
Chemicals	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Chemicals	Int. Lighting	4' Fluor	35.2%	35.1%
		Existing	38.7%	38.7%
		Base	52.0%	52.0%
		Hi-Eff	9.3%	9.3%
Chemicals	Int. Lighting	8' Fluor	48.5%	48.5%
		Existing	40.9%	40.8%
		Base	50.8%	50.6%
		Hi-Eff	8.2%	8.6%
Chemicals	Int. Lighting	Incand.	4.4%	4.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Chemicals	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Chemicals	Ext Lighting	HID	70.2%	68.6%
		Existing	0.0%	0.0%
		Base	63.6%	78.0%
		Hi-Eff	36.4%	22.0%
Chemicals	Ext Lighting	Fluor	16.9%	18.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Chemicals	Ext Lighting	Incand.	12.9%	13.3%
		Existing	0.0%	0.0%
		Base	80.6%	90.7%
		Hi-Eff	19.4%	9.3%
Chemicals	Other Process	Other Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Chemicals	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	Other	Other	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Chemicals	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	Process Machine Drive	Process Machine Drive	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	81.9%	81.9%
		Hi-Eff	18.1%	18.1%
Chemicals	Electrochecmical Process	Electrochemical Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Chemicals	N/A	N/A	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Chemicals	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Chemicals	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	HVAC	Heating	15.3%	15.3%
		Existing	0.0%	0.0%
		Base	13.1%	12.7%
		Hi-Eff	2.2%	2.6%
Mining	HVAC	Ventilation	20.9%	20.9%
		Existing	0.0%	0.0%
		Base	17.6%	17.2%
		Hi-Eff	3.3%	3.7%
Mining	HVAC	Air Conditioning	63.8%	63.8%
		Existing	22.0%	21.5%
		Base	33.4%	32.7%
		Hi-Eff	8.4%	9.6%
Mining	Process Coooling	Process Cooling	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	85.6%	85.6%
		Hi-Eff	14.4%	14.4%
Mining	Process Coooling	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	Process Heating & Boiler Fuel	Process Heating & Boiler Fuel	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	89.0%	89.0%
		Hi-Eff	11.0%	11.0%
Mining	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	Process Heating & Boiler Fuel	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	Int. Lighting	4' Fluor	35.2%	35.1%
		Existing	38.7%	38.7%
		Base	52.0%	52.0%
		Hi-Eff	9.3%	9.3%
Mining	Int. Lighting	8' Fluor	48.5%	48.5%
		Existing	40.9%	40.8%
		Base	50.8%	50.6%
		Hi-Eff	8.2%	8.6%
Mining	Int. Lighting	Incand.	4.4%	4.4%
		Existing	0.0%	0.0%
		Base	75.5%	75.5%
		Hi-Eff	24.5%	24.5%
Mining	Int. Lighting	Exit Signs	12.0%	12.0%
		Existing	0.0%	0.0%
		Base	16.3%	16.3%
		Hi-Eff	83.7%	83.7%
Mining	Ext Lighting	HID	70.2%	68.6%
		Existing	0.0%	0.0%
		Base	63.6%	78.0%
		Hi-Eff	36.4%	22.0%
Mining	Ext Lighting	Fluor	16.9%	18.1%
		Existing	33.2%	33.9%
		Base	57.2%	58.3%
		Hi-Eff	9.6%	7.8%
Mining	Ext Lighting	Incand.	12.9%	13.3%
		Existing	0.0%	0.0%
		Base	80.6%	90.7%
		Hi-Eff	19.4%	9.3%

Industrial End Use and Technology Type Segmentation

Subsector	End Use	Technology Type	% MWh Segmentation	% MW Segmentation
Mining	Other Process	Other Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Mining	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	Other Process	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	Other	Other	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Mining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	Other	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	Process Machine Drive	Process Machine Drive	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	81.9%	81.9%
		Hi-Eff	18.1%	18.1%
Mining	Electrochecmical Process	Electrochemical Process	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	80.0%	80.0%
		Hi-Eff	20.0%	20.0%
Mining	N/A	N/A	100.0%	100.0%
		Existing	0.0%	0.0%
		Base	100.0%	100.0%
		Hi-Eff	0.0%	0.0%
Mining	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%
Mining	N/A	N/A	0.0%	0.0%
		Existing	0.0%	0.0%
		Base	0.0%	0.0%
		Hi-Eff	0.0%	0.0%

Appendix E

Detailed Accounting Model Results

Appendix: Detailed Accounting Model Outputs

Table 1. Electric Base Forecasts and Achievable Potential Scenarios

Electric Base Forecast and Decrements - All Sectors

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	145,271,108	147,087,212	148,916,815	150,789,433	152,740,282	154,784,424	156,926,718	159,171,753	161,523,715	163,986,246	166,563,340	169,257,020	172,068,703	174,997,495	178,045,208	181,079,862	184,239,113	187,522,625	190,929,690	194,464,646	198,121,459
Base Forecast	143,627,011	144,725,376	145,850,102	147,001,491	148,179,850	149,385,497	150,618,756	151,879,961	153,169,451	154,487,578	155,834,699	157,211,181	158,617,398	160,053,736	161,520,588	163,018,356	164,547,453	166,108,299	167,701,326	169,326,974	170,985,694
DSM25	143,627,011	144,672,712	145,674,723	146,616,999	147,478,921	148,240,144	148,882,428	149,393,010	149,766,178	150,007,042	150,146,510	150,190,940	150,181,781	150,165,932	150,200,341	150,279,326	150,525,266	151,000,704	151,744,974	152,604,390	153,769,936
DSM50	143,627,011	144,547,982	145,210,503	145,493,802	145,259,822	144,409,488	142,956,518	141,024,939	138,899,697	136,970,623	135,398,851	134,433,713	134,404,245	134,415,224	135,063,271	135,787,180	136,819,569	138,077,302	139,573,508	141,326,502	143,293,923
DSM100	143,627,011	144,392,700	144,549,232	143,735,708	141,680,303	138,472,183	134,798,999	131,433,589	129,154,276	127,849,620	127,540,380	127,931,637	128,579,067	129,596,991	131,004,459	132,617,674	134,424,818	136,358,547	138,398,610	140,545,195	142,763,974
DSM100 Plus Standards	143,627,011	144,392,700	144,549,232	125,318,350	122,489,942	122,173,115	121,645,720	121,347,137	121,623,248	122,471,377	123,725,786	125,217,063	126,848,258	128,577,402	130,389,228	132,193,563	134,076,911	136,036,116	138,106,746	140,253,263	142,468,253
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	23,572	24,068	24,555	25,062	25,668	26,054	26,573	27,104	27,661	28,217	28,896	29,520	30,163	30,823	31,500	32,112	32,743	33,392	34,057	34,739	35,435
Base Forecast	23,268	23,583	23,889	24,210	24,623	24,804	25,106	25,409	25,723	26,022	26,430	26,769	27,113	27,461	27,813	28,170	28,531	28,898	29,269	29,644	30,025
DSM25	23,268	23,574	23,858	24,143	24,500	24,604	24,804	24,979	25,141	25,267	25,485	25,628	25,776	25,941	26,132	26,326	26,555	26,823	27,130	27,417	27,749
DSM50	23,268	23,552	23,777	23,949	24,117	23,957	23,828	23,646	23,479	23,361	23,377	23,423	23,614	23,758	23,957	24,133	24,351	24,619	24,935	25,297	25,699
DSM100	23,268	23,525	23,664	23,652	23,530	23,035	22,639	22,277	22,095	22,047	22,138	22,269	22,435	22,680	23,020	23,368	23,758	24,173	24,605	25,051	25,508
DSM100 Plus Standards	23,268	23,525	23,664	20,993	20,395	20,179	20,084	20,108	20,330	20,626	21,046	21,439	21,853	22,281	22,721	23,120	23,532	23,955	24,392	24,838	25,292

Residential Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	42,426,726	42,390,412	42,369,095	42,363,295	42,373,479	42,400,027	42,443,192	42,503,067	42,579,532	42,672,222	42,781,492	42,906,181	43,045,028	43,195,004	43,356,333	43,459,854	43,575,227	43,700,944	43,835,558	43,983,139	44,137,951
Base Forecast	42,230,046	41,986,136	41,747,592	41,514,356	41,286,371	41,063,583	40,845,936	40,633,378	40,425,857	40,223,323	40,025,725	39,833,017	39,645,149	39,462,077	39,283,756	39,110,141	38,941,189	38,776,860	38,617,111	38,461,904	38,311,200
DSM25	42,230,046	41,973,847	41,707,295	41,426,433	41,127,015	40,804,851	40,455,433	40,076,034	39,665,414	39,226,113	38,778,573	38,310,493	37,836,338	37,367,379	36,916,144	36,451,021	36,018,940	35,627,574	35,284,275	35,000,055	34,775,248
DSM50	42,230,046	41,944,914	41,601,236	41,169,599	40,617,147	39,918,250	39,084,821	38,136,890	37,141,872	36,180,448	35,334,935	34,672,079	34,216,063	33,920,501	33,775,423	33,660,992	33,582,719	33,531,044	33,498,980	33,500,137	33,515,867
DSM100	42,230,046	41,909,099	41,450,116	40,761,154	39,780,212	38,506,308	37,091,972	35,764,395	34,688,697	34,030,794	33,717,519	33,555,647	33,445,189	33,371,166	33,333,132	33,275,045	33,239,141	33,220,694	33,228,598	33,274,697	33,328,694
DSM100 Plus Standards	42,230,046	41,909,099	41,450,116	38,654,795	37,289,590	36,623,395	35,776,790	34,871,767	34,140,946	33,673,564	33,424,803	33,298,067	33,229,483	33,190,598	33,171,674	33,124,250	33,093,127	33,076,434	33,110,213	33,156,492	33,210,285
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	5,886	5,966	6,044	6,126	6,230	6,280	6,359	6,438	6,521	6,601	6,705	6,793	6,882	6,972	7,060	7,088	7,117	7,146	7,174	7,202	7,228
Base Forecast	5,801	5,796	5,787	5,781	5,796	5,755	5,742	5,727	5,715	5,699	5,705	5,695	5,685	5,675	5,665	5,656	5,646	5,636	5,627	5,617	5,608
DSM25	5,801	5,794	5,781	5,768	5,771	5,715	5,681	5,641	5,599	5,550	5,523	5,482	5,447	5,422	5,410	5,390	5,380	5,379	5,385	5,394	5,406
DSM50	5,801	5,789	5,765	5,728	5,691	5,576	5,471	5,356	5,253	5,173	5,149	5,141	5,153	5,159	5,159	5,114	5,078	5,060	5,055	5,058	5,066
DSM100	5,801	5,784	5,741	5,664	5,560	5,368	5,207	5,086	5,010	4,988	4,973	4,937	4,909	4,903	4,931	4,932	4,939	4,948	4,959	4,973	4,986
DSM100 Plus Standards	5,801	5,784	5,741	5,353	5,114	4,849	4,647	4,522	4,522	4,549	4,599	4,642	4,686	4,731	4,777	4,784	4,793	4,802	4,815	4,828	4,840

Commercial Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	55,763,906	56,940,468	58,096,990	59,272,797	60,489,711	61,757,304	63,079,056	64,458,497	65,899,149	67,404,466	68,977,769	70,622,176	72,340,537	74,135,373	76,008,823	77,919,126	79,914,300	81,995,821	84,164,605	86,420,944	88,764,435
Base Forecast	54,554,001	55,409,577	56,281,092	57,168,852	58,073,169	58,994,361	59,932,754	60,888,678	61,862,471	62,854,477	63,865,048	64,894,541	65,943,321	67,011,761	68,100,239	69,209,143	70,338,868	71,489,815	72,662,396	73,857,028	75,074,139
DSM25	54,554,001	55,387,973	56,208,066	57,007,902	57,777,111	58,504,819	59,180,962	59,796,814	60,346,251	60,827,053	61,242,101	61,600,409	61,917,966	62,218,252	62,532,008	62,876,754	63,306,550	63,858,599	64,562,226	65,229,636	66,055,392
DSM50	54,554,001	55,336,661	56,013,699	56,533,894	56,828,495	56,839,183	56,547,519	56,000,650	55,329,084	54,731,548	54,187,319	54,010,062	54,328,679	54,554,734	55,157,929	55,820,156	56,623,879	57,523,831	58,537,897	59,681,700	60,951,414
DSM100	54,554,001	55,272,569	55,735,080	55,784,536	55,265,775	54,187,482	52,856,222	51,516,169	50,755,849	50,349,174	50,476,522	50,973,861	51,567,940	52,310,152	53,234,751	54,284,338	55,443,009	56,676,822	57,969,876	59,316,083	60,713,279
DSM100 Plus Standards	54,554,001	55,272,569	55,735,080	46,505,672	45,168,831	45,517,058	45,847,227	46,308,165	46,961,484	47,772,806	48,688,731	49,674,941	50,715,189	51,802,921	52,935,884	54,085,177	55,282,451	56,527,761	57,821,541	59,166,800	60,561,021
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	9,997	10,267	10,532	10,807	11,129	11,358	11,649	11,949	12,264	12,583	12,962	13,321	13,692	14,077	14,475	14,867	15,273	15,693	16,126	16,571	17,028
Base Forecast	9,815	10,017	10,218	10,427	10,677	10,828	11,033	11,240	11,454	11,662	11,921	12,151	12,385	12,622	12,863	13,108	13,356	13,609	13,866	14,127	14,391
DSM25	9,815	10,013	10,203	10,393	10,615	10,727	10,880	11,021	11,156	11,274	11,431	11,554	11,679	11,810	11,953	12,104	12,272	12,462	12,676	12,852	13,058
DSM50	9,815	10,002	10,163	10,297	10,426	10,408	10,399	10,365	10,336	10,329	10,341	10,391	10,530	10,634	10,785	10,956	11,139	11,339	11,560	11,803	12,070
DSM100	9,815	9,989	10,107	10,153	10,144	9,970	9,840	9,675	9,614	9,613	9,706	9,840	9,989	10,165	10,376	10,607	10,860	11,129	11,408	11,696	11,992
DSM100 Plus Standards	9,815	9,989	10,107	8,834	8,477	8,536	8,627	8,739	8,890	9,068	9,303	9,531	9,771	10,020	10,278	10,533	10,797	11,068	11,347	11,634	11,928

Industrial Electric Base Forecast and Decrements

Energy Sales Forecasts (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Static Efficiency	47,080,476	47,756,332	48,450,730	49,153,341	49,877,092	50,627,093	51,404,469	52,210,190	53,045,034	53,909,558	54,804,079	55,728,663	56,683,138	57,667,119	58,680,052	59,700,881	60,749,586	61,825,860	62,929,527	64,060,564	65,219,073
Base Forecast	46,842,965	47,329,663	47,821,418	48,318,283	48,820,310	49,327,553	49,840,066	50,357,904	50,881,123	51,409,778	51,943,926	52,483,623	53,028,928	53,579,898	54,136,594	54,699,073	55,267,396	55,841,624	56,421,819	57,008,042	57,600,355
DSM25	46,842,965	47,310,892	47,759,361	48,182,664	48,574,795	48,930,473	49,246,033	49,520,162	49,754,513	49,953,876	50,125,836	50,280,037	50,427,477	50,580,301	50,752,189	50,951,550	51,199,777	51,514,531	51,898,472	52,374,699	52,939,297
DSM50	46,842,965	47,266,407	47,595,568	47,790,308	47,814,180	47,652,055	47,324,178	46,887,400	46,428,741	46,058,627	45,876,596	45,751,572	45,859,503	45,939,989	46,129,918	46,306,032	46,612,971	47,022,427	47,536,631	48,144,665	48,826,641
DSM100	46,842,965	47,211,032	47,364,036	47,190,018	46,634,316	45,778,394	44,850,805	44,153,025	43,709,730	43,469,652	43,346,340	43,402,129	43,565,939	43,915,673	44,436,575	45,058,292	45,742,669	46,461,030	47,200,136	47,954,415	48,722,002
DSM100 Plus Standards	46,842,965	47,211,032	47,364,036	40,157,883	40,031,522	40,032,662	40,021,702	40,167,205	40,520,818	41,025,006	41,612,253	42,244,055	42,903,587	43,583,883	44,281,669	44,984,137	45,701,333	46,431,921	47,174,991	47,929,971	48,696,946
Peak Demand Forecasts (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Static Efficiency	7,689	7,835	7,979	8,128	8,309	8,415	8,564	8,717	8,876	9,033	9,230	9,407	9,588	9,774	9,965	10,157	10,353	10,553	10,758	10,967	11,180
Base Forecast	7,652	7,769	7,883	8,002	8,150	8,221	8,331	8,441	8,554	8,661	8,804	8,923	9,043	9,163	9,285	9,407	9,529	9,652	9,776	9,901	10,026
DSM25	7,652	7,767	7,874	7,982	8,114	8,162	8,243	8,316	8,386	8,444	8,531	8,592	8,650	8,709	8,769	8,833	8,903	8,981	9,069	9,170	9,285
DSM50	7,652	7,760	7,850	7,924	8,000	7,972	7,958	7,925	7,891	7,860	7,887	7,891	7,931	7,964	8,012	8,063	8,133	8,219	8,321	8,436	8,563
DSM100	7,652	7,752	7,816	7,835	7,826	7,696	7,592	7,516	7,471	7,446	7,460	7,491	7,538	7,612	7,712	7,829	7,959	8,096	8,237	8,382	8,530
DSM100 Plus Standards	7,652	7,752	7,816	6,806	6,804	6,794	6,810	6,847	6,918	7,010	7,143	7,267	7,396	7,529	7,666	7,803	7,943	8,086	8,230	8,376	8,524

Figure 3. Residential Sector Achievable Potential Scenarios (Electricity Sales)

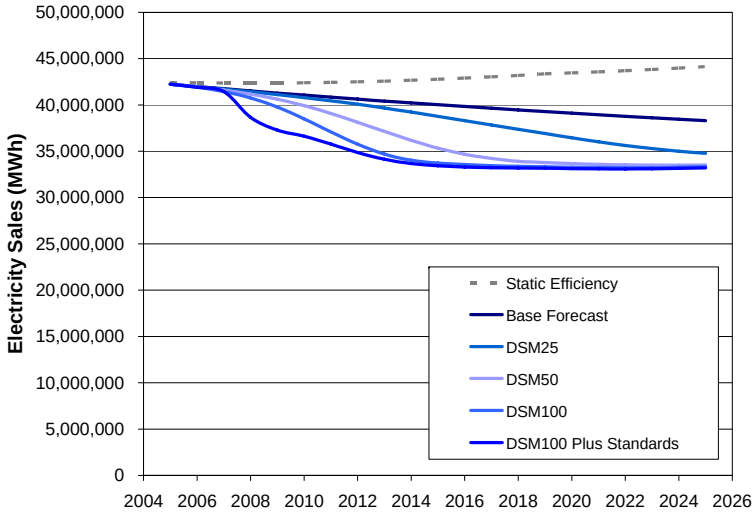


Figure 4. Residential Sector Achievable Potential Scenarios (Peak Demand)

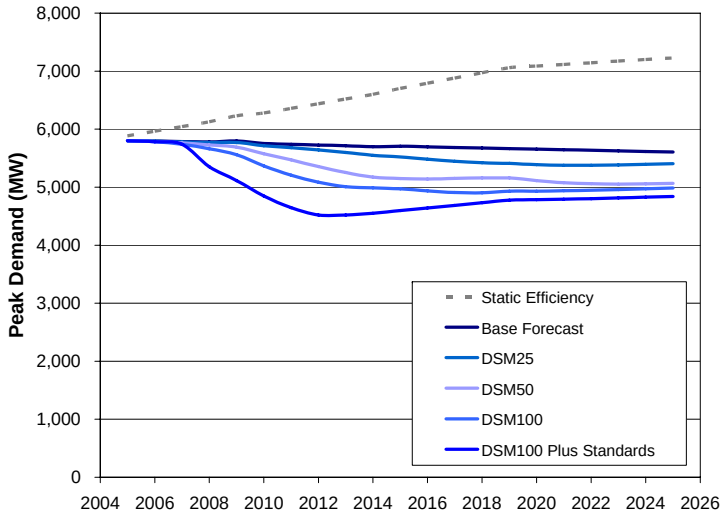


Figure 5. 2015 Residential Sector Achievable Potential by End Use (DSM50, Electricity Sales)

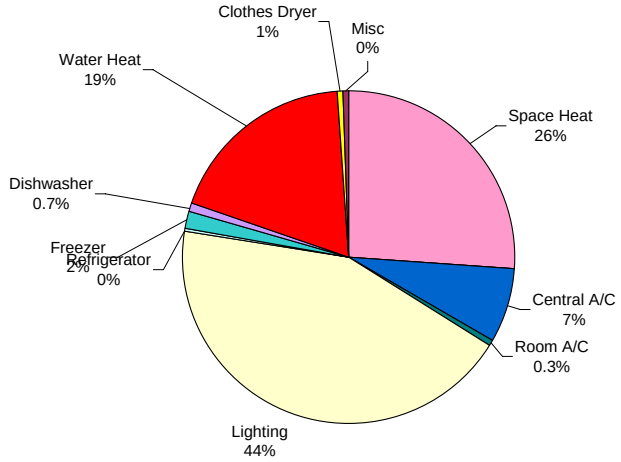


Figure 6. 2015 Residential Sector Achievable Potential by End Use (DSM50, Peak Demand)

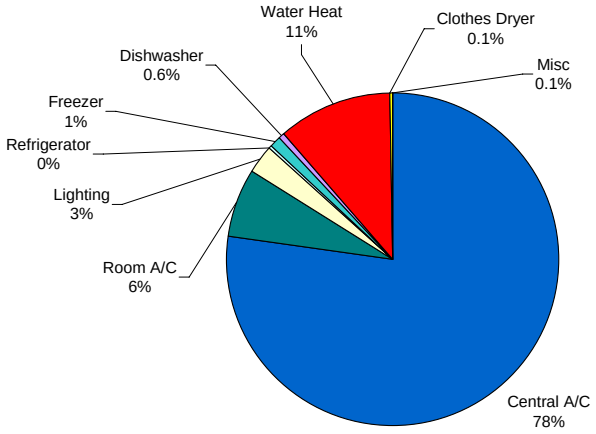


Table 2. Residential Sector Results by End Use

DSM25 Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	4,029	13,341	29,346	53,537	87,355	131,966	187,968	255,034	331,569	414,471	499,147	579,870	650,502	705,440	741,030	754,966	747,496	720,841	678,587	624,953
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	1,012	3,404	7,610	14,104	23,356	35,754	51,491	70,417	91,880	114,599	136,626	155,493	168,571	173,618	181,662	182,484	176,902	166,336	152,390	136,528
Room A/C	-	80	265	580	1,049	1,689	2,502	3,470	4,543	5,635	6,632	7,398	7,809	7,775	7,269	6,946	6,371	5,643	4,853	4,069	3,335
Lighting	-	1,958	6,653	15,085	28,533	48,599	77,255	116,880	170,254	240,495	330,896	444,617	584,176	750,732	943,186	1,157,245	1,384,758	1,613,724	1,829,381	2,016,493	2,162,358
Refrigerator	-	599	1,632	2,913	4,249	5,465	6,415	6,999	7,156	6,868	(7,509)	(18,517)	(25,859)	(29,272)	(28,558)	(6,527)	18,030	44,995	74,120	100,608	127,970
Freezer	-	71	180	299	409	494	1,467	3,807	7,694	13,299	19,912	27,787	36,942	47,314	58,756	71,044	83,896	96,992	110,006	122,623	134,560
Dishwasher	-	10	28	50	72	91	104	108	104	90	67	3,901	8,307	13,414	18,689	23,836	28,529	32,478	35,497	37,554	38,765
Water Heat	-	4,354	14,321	31,197	56,167	90,067	133,087	184,419	241,934	302,000	359,592	408,823	443,909	460,388	456,198	442,588	413,232	372,141	323,890	272,737	222,112
Clothes Dryer	-	41	108	189	271	346	406	500	1,121	2,344	4,243	6,879	10,297	14,456	19,122	24,239	29,723	35,465	41,342	47,226	52,992
Misc	-	134	364	653	965	1,270	1,546	1,703	2,188	3,029	4,250	5,862	7,867	10,816	13,892	17,056	20,260	23,450	26,569	29,561	32,378
Total	-	12,289	40,297	87,923	159,357	258,732	390,503	557,344	760,443	997,210	1,247,153	1,522,523	1,808,812	2,094,698	2,367,612	2,659,119	2,922,250	3,149,286	3,332,836	3,461,849	3,535,952

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	1.3	4.3	9.5	17.4	28.7	43.6	62.4	85.0	110.4	137.1	162.4	183.1	195.4	196.2	203.3	201.3	191.6	176.3	157.4	137.0
Room A/C	-	0.2	0.6	1.4	2.5	4.1	6.0	8.2	10.7	13.2	15.5	17.2	18.0	17.9	16.7	15.8	14.3	12.5	10.6	8.7	7.0
Lighting	-	0.0	0.1	0.1	0.2	0.4	0.6	0.9	1.4	1.9	2.6	3.5	4.6	5.9	7.4	9.0	10.7	12.5	14.0	15.4	16.3
Refrigerator	-	0.1	0.2	0.3	0.4	0.6	0.6	0.7	0.7	0.7	(0.8)	(2.1)	(3.0)	(3.5)	(3.6)	(1.6)	0.6	3.1	5.7	8.1	10.6
Freezer	-	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.6	1.0	1.6	2.3	3.1	4.0	5.0	6.1	7.2	8.3	9.5	10.5	11.6
Dishwasher	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.8	1.3	1.8	2.3	2.7	3.0	3.3	3.5	3.6
Water Heat	-	0.3	1.1	2.3	4.1	6.6	9.7	13.4	17.4	21.6	25.7	29.0	31.3	32.2	31.6	30.3	27.9	24.7	21.1	17.4	13.7
Clothes Dryer	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1
Misc	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.6	0.6	0.7
Total	-	1.9	6.2	13.6	24.8	40.3	60.7	86.0	115.9	148.9	181.8	213.0	238.3	253.6	255.6	265.9	265.8	257.0	241.9	222.7	201.6

DSM50 Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	13,617	48,931	116,072	225,062	380,812	576,258	788,667	985,258	1,136,979	1,230,048	1,266,997	1,265,679	1,265,891	1,223,180	1,164,463	1,107,461	1,049,781	988,633	922,609	852,429
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	3,420	12,530	30,350	60,188	104,265	161,328	224,422	281,637	321,328	338,059	333,755	320,582	310,690	303,643	315,939	324,326	324,266	318,377	308,520	296,524
Room A/C	-	271	965	2,260	4,287	7,011	10,110	12,993	15,051	15,965	15,779	17,310	15,937	14,764	13,732	13,736	13,573	13,221	12,743	12,230	11,748
Lighting	-	6,679	25,011	62,890	132,344	250,550	439,339	720,533	1,103,843	1,568,281	2,050,835	2,465,299	2,750,078	2,900,532	2,953,661	2,951,829	2,923,023	2,880,801	2,830,449	2,773,637	2,710,690
Refrigerator	-	1,808	4,827	8,296	11,524	14,028	1,568	(5,176)	(4,842)	3,493	19,841	43,145	71,615	103,287	136,472	184,208	230,090	273,711	314,867	349,609	381,328
Freezer	-	202	486	764	1,870	5,622	12,766	23,839	38,908	57,473	77,959	99,450	121,034	142,017	161,917	180,423	197,343	212,562	226,017	228,559	229,673
Dishwasher	-	32	86	148	203	243	4,276	10,021	17,313	25,274	32,408	37,381	39,904	40,909	41,058	40,926	40,730	40,524	40,320	40,118	39,917
Water Heat	-	14,685	52,206	121,750	230,294	376,547	544,410	703,017	819,205	875,014	873,858	831,782	764,265	669,043	566,485	476,573	388,975	307,128	233,081	167,182	108,874
Clothes Dryer	-	119	302	501	725	1,969	4,535	8,650	14,366	21,515	29,765	38,733	48,076	57,485	66,560	75,175	83,246	90,719	97,559	103,744	109,259
Misc	-	389	1,014	1,726	2,726	4,285	6,527	9,523	13,245	17,553	22,238	27,085	31,916	36,959	41,624	45,877	49,703	53,104	56,086	55,559	54,890
Total	-	41,221	146,356	344,757	669,224	1,145,333	1,761,115	2,496,488	3,283,985	4,042,875	4,690,790	5,160,938	5,429,087	5,541,576	5,508,332	5,449,149	5,358,470	5,245,816	5,118,132	4,961,767	4,795,333

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	4.3	15.7	37.9	75.3	130.2	201.8	281.8	355.4	407.1	429.4	421.5	400.9	388.1	381.9	416.8	444.5	453.8	451.3	441.1	427.0
Room A/C	-	0.7	2.3	5.4	10.3	16.7	23.9	30.4	34.8	36.6	35.9	37.8	34.5	31.5	28.8	28.0	27.0	25.6	24.0	22.4	20.9
Lighting	-	0.1	0.2	0.5	1.1	2.0	3.6	5.8	8.9	12.5	16.3	19.5	21.7	22.7	23.0	22.8	22.5	22.0	21.5	20.9	20.3
Refrigerator	-	0.2	0.5	0.8	1.2	1.4	(0.1)	(1.0)	(1.2)	(0.7)	0.8	2.9	5.4	8.2	11.2	15.6	19.8	23.8	27.6	30.7	33.6
Freezer	-	0.0	0.0	0.1	0.2	0.4	1.0	1.9	3.2	4.8	6.7	8.6	10.5	12.3	14.1	15.7	17.1	18.4	19.6	19.7	19.6
Dishwasher	-	0.0	0.0	0.0	0.0	0.0	0.4	1.0	1.7	2.4	3.1	3.6	3.8	3.9	3.9	3.8	3.8	3.8	3.7	3.7	3.6
Water Heat	-	1.1	3.9	9.0	17.0	27.6	39.6	50.8	58.9	62.4	62.0	58.6	53.8	47.5	41.1	35.8	30.6	25.7	21.0	16.7	12.7
Clothes Dryer	-	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0	2.1	2.2	2.3
Misc	-	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.2	1.2	1.2
Total	-	6.3	22.7	53.9	105.1	178.5	270.4	371.1	462.3	526.0	555.4	553.9	532.3	516.3	506.3	541.2	568.2	576.2	572.0	558.7	541.3

Residential Sector Results by End Use *(continued)*

DSM100 Scenario

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	25,620	100,057	252,370	496,612	799,692	1,085,367	1,290,430	1,419,343	1,527,560	1,524,864	1,484,871	1,445,082	1,397,606	1,338,315	1,269,538	1,193,522	1,113,339	1,031,264	948,994	867,897
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	6,442	25,769	67,024	136,948	228,824	317,900	379,042	405,426	404,912	410,349	419,873	426,233	421,870	403,893	397,098	387,149	375,802	363,862	351,753	339,780
Room A/C	-	507	1,953	4,794	9,024	13,675	17,328	19,267	24,489	23,342	22,457	21,601	20,482	19,038	17,415	16,740	16,048	15,384	14,773	14,232	13,770
Lighting	-	12,713	53,132	150,241	353,787	728,542	1,305,194	1,989,101	2,569,115	2,910,521	3,050,429	3,084,292	3,074,862	3,048,792	3,015,121	2,976,455	2,933,325	2,885,621	2,833,030	2,775,177	2,711,670
Refrigerator	-	3,004	7,716	12,602	2,550	1,209	11,492	33,844	65,421	102,037	140,323	178,285	214,944	249,882	282,955	327,949	369,915	408,951	445,164	451,426	456,023
Freezer	-	317	722	1,943	7,301	18,338	35,395	57,135	81,492	106,751	131,289	154,597	176,391	196,533	214,951	231,611	246,493	259,592	261,799	262,615	262,067
Dishwasher	-	54	141	230	300	4,386	11,532	21,556	31,784	38,609	41,304	41,744	41,496	41,323	41,118	40,911	40,706	40,501	40,298	40,096	39,894
Water Heat	-	27,570	105,986	260,357	491,904	747,446	943,666	1,038,911	1,085,341	1,008,549	901,606	791,646	685,728	587,216	495,359	421,526	350,920	283,368	219,245	159,158	103,766
Clothes Dryer	-	190	459	752	2,638	6,733	13,203	21,566	31,046	40,990	50,992	60,839	70,427	79,661	88,303	96,330	103,727	110,482	116,586	122,031	126,812
Misc	-	622	1,542	2,889	5,096	8,429	12,886	18,130	23,705	29,258	34,593	39,621	44,315	48,991	53,194	56,939	60,244	63,126	62,493	61,726	60,827
Total	-	77,037	297,476	753,202	1,506,159	2,557,275	3,753,964	4,868,983	5,737,160	6,192,529	6,308,207	6,277,369	6,199,961	6,090,912	5,950,623	5,835,096	5,702,048	5,556,166	5,388,513	5,187,207	4,982,506

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	8.2	32.5	84.4	173.5	291.8	410.3	496.3	537.3	541.6	563.5	592.2	615.2	615.8	584.2	575.8	561.6	545.2	528.3	511.4	495.1
Room A/C	-	1.2	4.7	11.5	21.6	32.3	40.4	44.3	53.1	50.1	47.9	45.6	42.6	39.1	35.2	33.1	31.0	29.0	27.1	25.4	23.9
Lighting	-	0.1	0.4	1.2	2.9	5.9	10.6	16.0	20.6	23.2	24.2	24.4	24.2	23.8	23.4	23.0	22.5	22.0	21.5	20.9	20.3
Refrigerator	-	0.3	0.8	1.3	0.3	(0.4)	0.3	2.2	5.0	8.2	12.0	15.4	18.7	21.9	24.8	29.0	32.8	36.4	39.7	39.9	40.0
Freezer	-	0.0	0.1	0.2	0.7	1.5	3.0	4.9	7.0	9.2	11.5	13.5	15.4	17.2	18.8	20.2	21.5	22.6	22.7	22.6	22.4
Dishwasher	-	0.0	0.0	0.0	0.0	0.4	1.1	2.1	3.1	3.7	4.0	4.0	3.9	3.9	3.9	3.8	3.8	3.7	3.7	3.7	3.6
Water Heat	-	2.0	7.8	19.2	36.3	54.7	68.6	75.0	78.2	73.2	67.0	60.5	53.9	47.4	40.9	35.6	30.4	25.5	20.8	16.4	12.5
Clothes Dryer	-	0.0	0.0	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1	2.2	2.4	2.5	2.6	2.7
Misc	-	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.3
Total	-	11.9	46.4	117.9	235.4	386.5	534.8	641.6	705.4	710.7	732.0	757.7	776.4	771.9	734.4	723.9	707.3	688.3	667.6	644.4	621.9

DSM100 Plus Aggressive Standards

Residential Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	25,620	100,057	1,211,158	1,861,674	1,842,652	1,824,041	1,797,607	1,758,869	1,708,589	1,649,485	1,583,882	1,513,276	1,438,608	1,360,569	1,280,876	1,199,109	1,116,047	1,032,562	949,603	868,165
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	6,442	25,769	169,810	321,815	465,779	575,011	632,669	627,390	609,540	588,980	567,010	544,213	520,895	497,303	489,017	479,928	470,346	460,490	450,570	440,811
Room A/C	-	507	1,953	35,202	34,210	33,438	32,655	31,573	30,118	28,408	26,573	24,687	22,793	20,920	19,098	18,340	17,604	16,909	16,273	15,707	15,223
Lighting	-	12,713	53,132	150,241	353,787	728,542	1,305,194	1,989,101	2,569,115	2,910,521	3,050,429	3,084,292	3,074,862	3,048,792	3,015,121	2,976,455	2,933,325	2,885,621	2,833,030	2,775,177	2,711,670
Refrigerator	-	3,004	7,716	(556)	42	12,515	37,303	71,438	110,581	151,247	191,386	230,001	266,678	301,284	333,817	378,015	419,092	457,166	466,795	471,466	474,545
Freezer	-	317	722	1,943	7,301	18,338	35,395	57,135	81,492	106,751	131,289	154,597	176,391	196,533	214,951	231,611	246,493	259,592	261,799	262,615	262,067
Dishwasher	-	54	141	4,385	11,747	22,025	32,483	39,449	42,190	42,617	42,333	41,920	41,506	41,304	41,094	40,884	40,676	40,468	40,262	40,056	39,852
Water Heat	-	27,570	105,986	1,283,738	1,398,471	1,301,735	1,200,975	1,102,942	1,010,407	921,838	834,862	748,099	661,206	574,490	488,632	417,425	347,864	280,668	216,609	156,459	100,943
Clothes Dryer	-	190	459	752	2,638	6,733	13,203	21,566	31,046	40,990	50,992	60,839	70,427	79,661	88,303	96,330	103,727	110,482	116,586	122,031	126,812
Misc	-	622	1,542	2,889	5,096	8,429	12,886	18,130	23,705	29,258	34,593	39,621	44,315	48,991	53,194	56,939	60,244	63,126	62,493	61,726	60,827
Total	-	77,037	297,476	2,859,561	3,996,781	4,440,188	5,069,146	5,761,611	6,284,911	6,549,759	6,600,923	6,534,949	6,415,667	6,271,479	6,112,082	5,985,891	5,848,062	5,700,426	5,506,898	5,305,412	5,100,915

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Furnace Fan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Central A/C	-	8.2	32.5	255.3	498.6	726.0	913.3	1,021.5	1,008.1	967.0	925.6	878.1	829.6	780.7	731.9	717.1	701.4	685.3	669.1	653.3	637.9
Room A/C	-	1.2	4.7	76.2	74.1	71.6	69.5	66.7	63.1	59.0	55.0	50.6	46.2	41.9	37.6	35.4	33.2	31.2	29.3	27.5	26.0
Lighting	-	0.1	0.4	1.2	2.9	5.9	10.6	16.0	20.6	23.2	24.2	24.4	24.2	23.8	23.4	23.0	22.5	22.0	21.5	20.9	20.3
Refrigerator	-	0.3	0.8	(0.2)	(0.2)	0.4	2.5	5.6	9.1	12.7	16.7	20.3	23.6	26.7	29.6	33.7	37.4	40.9	41.4	41.5	41.4
Freezer	-	0.0	0.1	0.2	0.7	1.5	3.0	4.9	7.0	9.2	11.5	13.5	15.4	17.2	18.8	20.2	21.5	22.6	22.7	22.6	22.4
Dishwasher	-	0.0	0.0	0.4	1.2	2.2	3.2	3.8	4.1	4.1	4.1	4.0	3.9	3.9	3.9	3.8	3.8	3.7	3.7	3.7	3.6
Water Heat	-	2.0	7.8	94.8	104.5	97.9	91.9	85.6	79.3	72.8	66.6	60.0	53.5	46.9	40.5	35.2	30.0	25.0	20.3	15.9	12.0
Clothes Dryer	-	0.0	0.0	0.0	0.1	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1	2.2	2.4	2.5	2.6	2.7
Misc	-	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.3
Total	-	11.9	46.4	427.9	682.0	905.9	1,094.5	1,205.0	1,192.6	1,149.6	1,105.5	1,053.1	998.9	943.9	888.7	871.7	853.4	834.5	811.9	789.4	767.8

Figure 7. Commercial Sector Achievable Potential Scenarios (Electricity Sales)

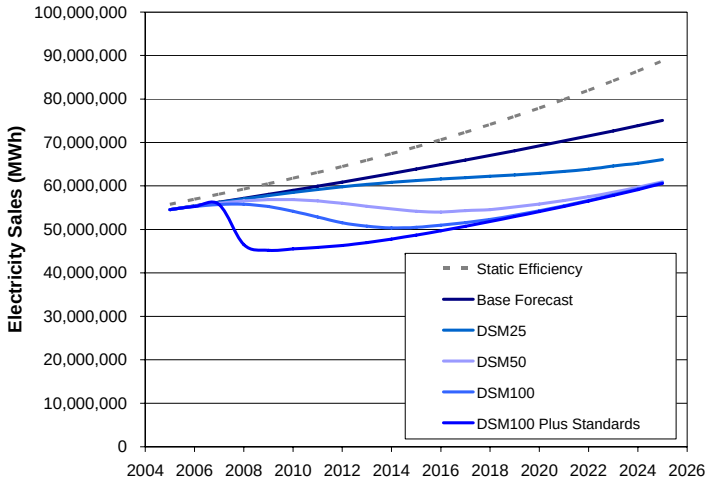


Figure 8. Commercial Sector Achievable Potential Scenarios (Peak Demand)

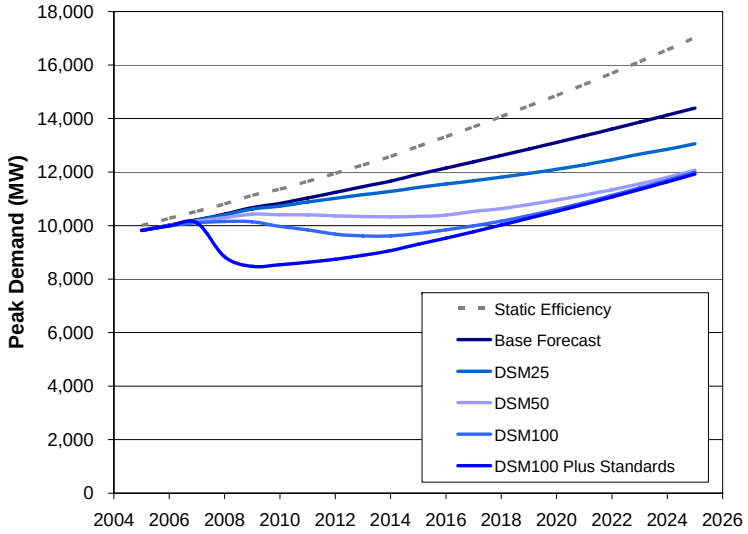


Figure 9. 2015 Commercial Sector Achievable Potential by End Use (DSM50, Electricity Sales)

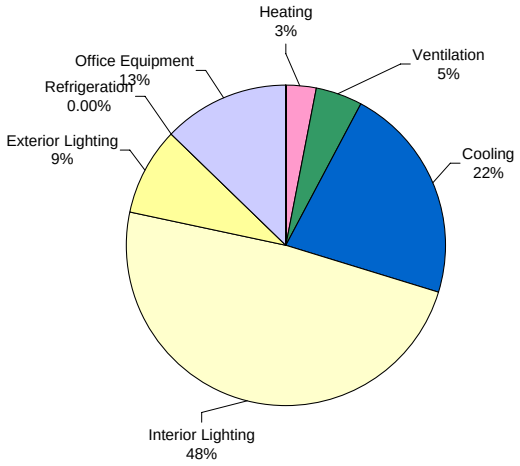


Figure 10. 2015 Commercial Sector Achievable Potential by End Use (DSM50, Peak Demand)

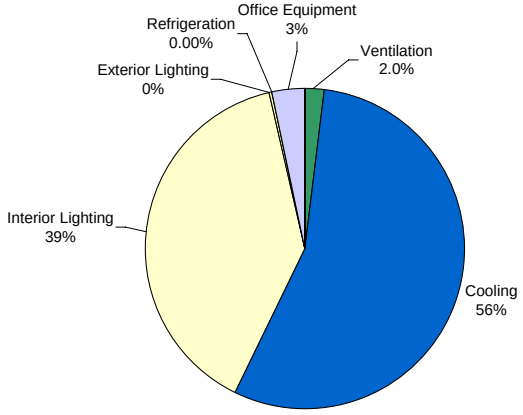


Figure 11. 2015 Commercial Sector Achievable Potential by Sub-sector (DSM50, Electricity Sales)

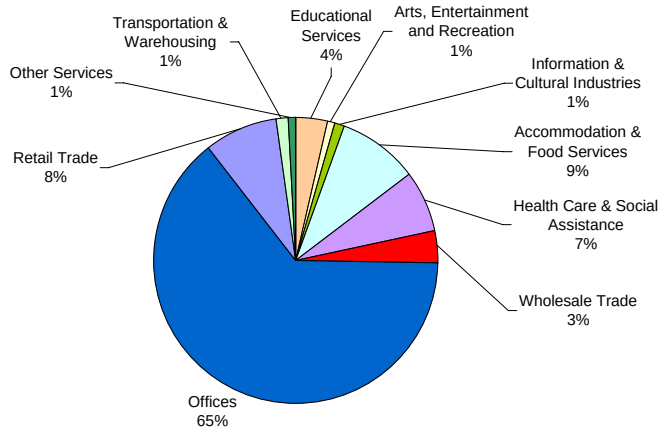


Figure 12. 2015 Commercial Sector Achievable Potential by Sub-sector (DSM50, Peak Demand)

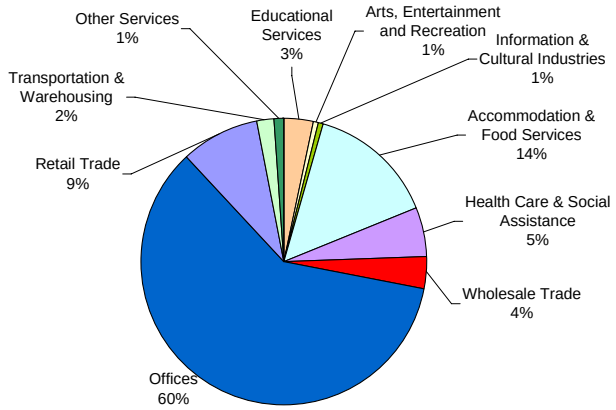


Table 3. Commercial Sector Results by End Use

DSM25 Scenario

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	474	1,618	3,678	6,961	11,831	18,707	28,035	40,248	55,696	74,540	96,630	121,379	147,692	173,985	198,363	218,935	234,195	243,323	246,289	243,711
Ventilation	-	3,789	12,345	26,559	47,053	73,923	106,481	143,031	180,846	216,412	246,003	266,474	275,987	274,388	263,072	244,425	221,135	195,649	169,896	153,240	142,021
Cooling	-	7,266	24,287	53,783	98,475	160,708	241,957	342,245	459,599	589,705	725,949	859,951	982,563	1,085,124	1,160,655	1,222,960	1,255,274	1,257,706	1,232,731	1,381,786	1,524,098
Interior Lighting	-	7,466	25,842	56,519	104,728	176,635	278,788	418,448	603,087	839,499	1,132,492	1,483,207	1,887,334	2,333,722	2,804,060	3,274,003	3,716,887	4,107,344	4,425,504	4,659,514	4,805,933
Exterior Lighting	-	886	3,050	7,006	13,417	23,116	37,132	56,692	83,211	118,234	163,332	219,922	289,007	370,838	464,546	568,672	678,938	789,926	895,313	988,869	1,065,613
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	1,722	5,885	13,404	25,424	43,328	68,728	103,413	149,228	207,878	280,631	367,948	469,084	581,745	701,913	823,967	941,150	1,046,396	1,133,402	1,197,696	1,237,371
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	21,605	73,026	160,950	296,057	489,542	751,792	1,091,864	1,516,220	2,027,425	2,622,947	3,294,132	4,025,355	4,793,509	5,568,231	6,332,389	7,032,318	7,631,216	8,100,169	8,627,393	9,018,747

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	0.3	0.9	1.8	3.3	5.1	7.4	9.9	12.4	14.8	16.8	18.1	18.7	18.5	17.6	16.2	14.6	12.8	11.1	10.1	9.2
Cooling	-	3.2	10.8	23.9	43.8	71.1	106.6	150.0	200.1	254.7	311.6	366.0	414.7	454.5	483.4	507.5	521.1	524.4	518.6	565.3	599.8
Interior Lighting	-	1.0	3.3	7.2	13.5	22.7	36.0	54.2	78.4	109.6	148.6	195.7	250.3	311.2	375.9	441.4	503.9	560.0	606.8	642.6	666.5
Exterior Lighting	-	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.6	0.9	1.2	1.6	2.0	2.6	3.2	3.9	4.6	5.3	5.9	6.5
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	0.1	0.3	0.6	1.1	1.9	3.0	4.5	6.5	9.1	12.3	16.1	20.5	25.4	30.5	35.7	40.6	44.8	48.2	50.4	51.5
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	4.5	15.2	33.6	61.8	101.0	153.1	218.8	297.9	388.7	490.1	597.1	705.8	811.6	910.0	1,004.1	1,084.1	1,146.7	1,190.0	1,274.3	1,333.5

DSM50 Scenario

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	1,613	6,034	15,061	31,140	57,053	94,822	143,683	198,195	249,038	287,660	311,041	321,734	330,721	331,580	327,064	321,462	314,492	305,905	295,612	283,700
Ventilation	-	12,704	44,230	99,725	179,254	273,242	362,682	427,951	460,052	462,941	456,106	438,135	402,707	366,537	330,205	294,333	259,545	226,441	195,552	167,310	142,021
Cooling	-	24,373	87,568	206,055	393,045	649,825	957,995	1,279,895	1,570,011	1,791,254	2,139,418	2,436,963	2,590,148	2,841,103	3,074,511	3,324,380	3,537,544	3,696,648	3,797,156	3,846,162	3,858,334
Interior Lighting	-	25,353	96,182	230,194	465,869	848,603	1,413,753	2,162,542	3,035,909	3,918,631	4,687,845	5,269,809	5,656,908	6,092,439	6,231,164	6,252,200	6,233,742	6,184,188	6,114,327	6,022,843	5,908,731
Exterior Lighting	-	3,015	11,415	28,942	61,170	115,687	201,332	325,528	489,097	680,253	873,389	1,038,677	1,158,084	1,240,786	1,287,999	1,341,519	1,350,795	1,357,544	1,361,430	1,362,107	1,359,224
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	5,857	21,963	54,981	114,196	210,768	354,650	548,431	780,123	1,020,813	1,233,310	1,389,855	1,485,060	1,585,440	1,686,850	1,849,490	2,011,900	2,186,671	2,350,128	2,481,293	2,570,716
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	72,916	267,393	634,958	1,244,674	2,155,178	3,385,235	4,888,028	6,533,387	8,122,930	9,677,729	10,884,479	11,614,642	12,457,026	12,942,309	13,388,987	13,714,989	13,965,984	14,124,499	14,175,328	14,122,725

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	0.9	3.1	6.9	12.4	18.9	24.9	29.3	31.4	31.4	31.0	29.6	27.1	24.5	21.9	19.4	17.1	14.8	12.7	10.9	9.2
Cooling	-	10.8	38.8	91.0	173.1	282.1	410.3	540.1	654.5	741.2	872.4	963.9	1,000.2	1,060.5	1,115.3	1,158.5	1,193.9	1,218.1	1,230.2	1,231.4	1,223.9
Interior Lighting	-	3.2	12.3	29.5	60.0	109.3	182.7	280.5	395.6	512.8	618.2	699.5	755.7	821.0	844.8	852.1	853.7	850.9	845.1	836.2	824.1
Exterior Lighting	-	0.0	0.1	0.1	0.3	0.6	1.0	1.7	2.6	3.8	5.0	6.0	6.8	7.3	7.7	8.1	8.3	8.4	8.6	8.7	8.8
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	0.3	0.9	2.4	5.0	9.2	15.5	23.9	34.0	44.5	53.8	60.7	64.8	74.0	87.7	113.6	144.0	177.5	209.6	236.4	255.8
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	15.2	55.2	129.9	250.8	420.1	634.4	875.6	1,118.1	1,333.7	1,580.4	1,759.7	1,854.5	1,987.4	2,077.6	2,151.8	2,217.0	2,269.7	2,306.3	2,323.5	2,321.7

Commercial Sector Results by End Use *(continued)*

DSM100 Scenario

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	3,058	12,655	34,737	76,724	141,161	215,804	277,529	313,877	337,623	344,201	344,175	343,313	341,045	337,149	331,724	324,891	316,695	307,141	296,229	283,984
Ventilation	-	23,667	87,412	199,604	338,399	454,327	515,437	541,772	535,177	504,766	472,301	438,135	402,707	366,537	330,205	294,333	259,545	226,441	195,552	167,310	142,021
Cooling	-	45,452	174,894	427,990	809,900	1,260,020	1,675,187	2,230,976	2,710,748	3,048,146	3,358,844	3,651,777	3,879,041	4,012,708	4,063,541	4,086,840	4,080,140	4,059,230	4,031,954	4,002,275	3,972,490
Interior Lighting	-	47,995	200,863	526,751	1,140,069	2,098,490	3,267,099	4,354,756	5,149,315	5,904,108	6,193,919	6,254,069	6,283,077	6,299,488	6,301,570	6,288,459	6,257,673	6,207,667	6,137,034	6,044,576	5,929,396
Exterior Lighting	-	5,725	24,074	67,918	157,561	315,105	543,310	799,515	1,012,878	1,160,266	1,267,210	1,295,612	1,309,378	1,321,781	1,332,596	1,344,439	1,354,093	1,361,239	1,365,542	1,366,654	1,364,221
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	11,111	46,114	127,315	284,741	537,777	859,697	1,167,960	1,384,627	1,550,395	1,752,051	1,936,912	2,157,864	2,360,049	2,500,425	2,579,010	2,619,517	2,641,720	2,655,297	2,663,901	2,668,747
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	137,008	546,012	1,384,316	2,807,394	4,806,880	7,076,532	9,372,509	11,106,622	12,505,304	13,388,526	13,920,680	14,375,381	14,701,608	14,865,487	14,924,805	14,895,859	14,812,993	14,692,520	14,540,945	14,360,860
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	1.6	6.0	13.8	23.4	31.3	35.3	37.1	36.4	34.1	32.0	29.6	27.1	24.5	21.9	19.4	17.1	14.8	12.7	10.9	9.2
Cooling	-	20.1	77.1	187.0	349.9	531.2	695.0	907.1	1,065.4	1,160.6	1,256.2	1,308.1	1,346.6	1,365.8	1,366.8	1,365.8	1,355.5	1,339.7	1,321.0	1,300.9	1,280.5
Interior Lighting	-	6.1	25.7	67.4	146.8	270.2	422.2	565.2	671.9	776.1	822.8	835.3	843.4	849.8	854.2	856.5	856.4	853.5	847.6	838.6	826.4
Exterior Lighting	-	0.0	0.1	0.3	0.8	1.7	3.0	4.5	5.8	6.6	7.3	7.6	7.8	8.0	8.2	8.4	8.5	8.7	8.8	8.9	9.0
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	0.5	2.0	5.5	12.4	23.4	37.5	50.9	60.4	72.2	97.3	130.3	170.7	208.5	235.2	250.5	258.7	263.8	267.7	271.0	274.1
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	28.4	111.0	274.1	533.3	857.8	1,192.9	1,564.8	1,839.9	2,049.6	2,215.7	2,310.8	2,395.5	2,456.6	2,486.4	2,500.7	2,496.2	2,480.5	2,457.8	2,430.3	2,399.2

DSM100 Plus Standards

Commercial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Heating	-	3,058	12,655	335,814	339,370	342,942	346,133	348,448	349,704	349,985	349,383	347,901	345,488	342,066	337,554	331,869	324,942	316,714	307,147	296,231	283,985
Ventilation	-	23,667	87,412	650,161	632,324	611,909	588,884	563,275	535,177	504,766	472,301	438,135	402,707	366,537	330,205	294,333	259,545	226,441	195,552	167,310	142,021
Cooling	-	45,452	174,894	2,216,490	3,186,382	3,472,077	3,793,186	4,057,401	4,219,567	4,295,081	4,316,881	4,309,310	4,285,795	4,253,118	4,214,854	4,197,922	4,176,226	4,151,565	4,125,298	4,098,642	4,072,761
Interior Lighting	-	47,995	200,863	4,800,355	5,838,603	5,922,199	6,001,634	6,075,849	6,143,670	6,203,892	6,255,281	6,296,551	6,326,340	6,343,208	6,345,650	6,332,924	6,302,673	6,253,395	6,183,702	6,089,841	5,973,704
Exterior Lighting	-	5,725	24,074	1,082,934	1,178,705	1,197,412	1,215,844	1,233,897	1,251,453	1,268,377	1,284,521	1,299,714	1,313,770	1,326,483	1,337,624	1,349,813	1,359,832	1,367,363	1,372,069	1,373,600	1,371,603
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	11,111	46,114	1,577,427	1,728,954	1,930,764	2,139,846	2,301,643	2,401,416	2,459,571	2,497,951	2,527,989	2,554,032	2,577,427	2,598,467	2,617,106	2,633,198	2,646,576	2,657,086	2,664,603	2,669,043
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	137,008	546,012	10,663,180	12,904,338	13,477,303	14,085,527	14,580,513	14,900,987	15,081,671	15,176,317	15,219,600	15,228,132	15,208,840	15,164,355	15,123,966	15,056,416	14,962,054	14,840,855	14,690,228	14,513,117
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ventilation	-	1.6	6.0	44.6	43.7	41.9	40.3	38.4	36.4	34.1	32.0	29.6	27.1	24.5	21.9	19.4	17.1	14.8	12.7	10.9	9.2
Cooling	-	20.1	77.1	855.6	1,290.2	1,338.6	1,403.5	1,458.7	1,493.2	1,505.6	1,510.1	1,500.0	1,483.6	1,463.2	1,440.0	1,426.3	1,410.4	1,393.0	1,374.8	1,356.3	1,338.0
Interior Lighting	-	6.1	25.7	607.7	754.9	764.8	779.0	792.3	805.2	816.2	830.6	840.4	848.8	855.3	859.9	862.3	862.3	859.6	854.0	845.0	832.7
Exterior Lighting	-	0.0	0.1	6.2	6.5	6.6	6.9	7.1	7.3	7.5	7.8	8.0	8.2	8.4	8.5	8.7	8.9	9.0	9.1	9.2	9.2
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Office Equipment	-	0.5	2.0	78.7	105.0	139.9	176.7	204.9	221.8	231.0	237.5	242.3	246.4	250.4	254.1	257.8	261.3	264.7	268.0	271.2	274.2
Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	28.4	111.0	1,592.8	2,200.2	2,291.8	2,406.3	2,501.4	2,563.9	2,594.5	2,618.0	2,620.3	2,614.1	2,601.7	2,584.5	2,574.5	2,559.9	2,541.1	2,518.6	2,492.4	2,463.3

Table 4. Commercial Sector Results by Sub-sector

DSM25 Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	758	2,576	5,641	10,364	17,184	26,518	38,761	54,245	73,185	95,632	121,411	150,061	180,784	212,417	244,015	273,548	299,378	320,162	337,009	347,862
Arts, Entertainment and Recreation	-	236	789	1,745	3,190	5,201	7,827	11,081	14,931	19,308	24,124	29,308	34,831	40,721	47,043	53,695	60,852	68,449	76,339	85,585	95,022
Information & Cultural Industries	-	261	888	1,950	3,571	5,874	8,963	12,917	17,774	23,520	30,086	37,341	45,094	53,095	61,029	68,590	75,377	81,068	85,435	89,315	91,991
Accommodation & Food Services	-	2,213	7,430	16,512	30,429	50,149	76,513	110,109	151,122	199,202	253,393	312,127	373,307	434,440	492,817	548,425	596,409	634,576	661,455	711,891	753,048
Health Care & Social Assistance	-	1,542	5,195	11,620	21,569	35,836	55,195	80,311	111,634	149,284	192,930	241,698	294,094	347,997	400,756	450,668	493,925	528,201	552,088	578,398	595,533
Wholesale Trade	-	940	3,115	6,841	12,455	20,276	30,561	43,455	58,945	76,824	96,667	117,842	139,530	160,766	180,501	198,215	212,564	222,852	228,724	233,805	235,187
Offices	-	12,588	42,836	94,355	174,023	289,257	447,186	654,546	916,941	1,238,018	1,618,576	2,055,638	2,541,525	3,063,050	3,601,218	4,144,683	4,655,906	5,107,303	5,475,616	5,885,564	6,200,315
Retail Trade	-	2,431	8,074	17,690	32,157	52,300	78,752	111,837	151,436	196,884	246,925	299,740	353,044	404,228	450,554	490,367	520,764	540,287	548,446	552,287	547,270
Transportation & Warehousing	-	419	1,398	3,026	5,458	8,847	13,312	18,928	25,708	33,580	42,370	51,793	61,440	70,795	79,267	86,391	91,571	94,490	95,076	94,146	91,457
Other Services	-	216	725	1,571	2,840	4,618	6,965	9,919	13,483	17,619	22,244	27,234	32,428	37,633	42,628	47,339	51,402	54,613	56,827	59,392	61,062
Total	-	21,605	73,026	160,950	296,057	489,542	751,792	1,091,864	1,516,220	2,027,425	2,622,947	3,294,132	4,025,355	4,793,509	5,568,231	6,332,389	7,032,318	7,631,216	8,100,169	8,627,393	9,018,747
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.1	0.4	0.9	1.7	2.7	4.2	6.1	8.5	11.4	14.7	18.4	22.4	26.5	30.7	34.8	38.5	41.7	44.3	46.8	48.5
Arts, Entertainment and Recreation	-	0.0	0.1	0.2	0.4	0.7	1.0	1.4	1.9	2.5	3.2	3.8	4.5	5.2	5.9	6.6	7.3	8.0	8.6	9.8	10.9
Information & Cultural Industries	-	0.0	0.1	0.2	0.3	0.6	0.9	1.3	1.8	2.4	3.0	3.8	4.6	5.4	6.2	7.0	7.7	8.3	8.7	9.2	9.6
Accommodation & Food Services	-	0.8	2.8	6.1	11.2	18.2	27.3	38.5	51.4	65.6	80.4	94.8	107.7	118.5	126.6	133.2	136.9	138.0	136.5	147.2	154.9
Health Care & Social Assistance	-	0.2	0.8	1.8	3.4	5.5	8.4	12.1	16.5	21.6	27.3	33.3	39.4	45.2	50.6	55.5	59.4	62.2	63.7	67.3	69.5
Wholesale Trade	-	0.2	0.7	1.5	2.7	4.4	6.6	9.3	12.4	15.8	19.5	23.1	26.4	29.3	31.7	33.5	34.7	35.1	34.9	35.3	35.2
Offices	-	2.4	8.0	17.7	32.7	53.8	82.2	118.6	163.1	215.5	275.6	341.3	410.8	481.7	551.3	621.0	684.0	737.6	779.1	845.1	893.6
Retail Trade	-	0.5	1.8	3.9	7.1	11.6	17.3	24.3	32.4	41.3	50.7	59.8	68.1	75.1	80.3	83.9	85.6	85.4	83.6	82.6	80.4
Transportation & Warehousing	-	0.1	0.4	0.8	1.4	2.3	3.4	4.8	6.5	8.4	10.5	12.6	14.6	16.5	18.1	19.3	20.1	20.4	20.2	20.1	19.7
Other Services	-	0.1	0.2	0.4	0.7	1.2	1.8	2.5	3.3	4.3	5.3	6.3	7.2	8.1	8.8	9.4	9.9	10.2	10.3	10.8	11.2
Total	-	4.5	15.2	33.6	61.8	101.0	153.1	218.8	297.9	388.7	490.1	597.1	705.8	811.6	910.0	1,004.1	1,084.1	1,146.7	1,190.0	1,274.3	1,333.5

DSM50 Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	2,562	9,467	22,395	44,042	76,940	122,325	179,068	242,668	305,552	362,005	404,489	430,605	459,920	471,773	478,275	481,138	482,059	480,748	476,725	469,987
Arts, Entertainment and Recreation	-	795	2,854	6,699	12,729	20,971	31,011	42,261	54,310	66,837	80,444	93,144	103,151	114,186	123,713	135,381	145,119	154,550	163,925	173,165	182,222
Information & Cultural Industries	-	881	3,241	7,626	14,742	25,049	38,429	54,062	70,428	85,598	98,811	108,411	113,810	119,672	121,014	121,846	121,047	119,767	118,069	115,984	113,549
Accommodation & Food Services	-	7,455	27,071	64,581	125,981	215,241	331,589	467,704	609,871	740,736	883,703	997,228	1,062,313	1,132,400	1,187,270	1,250,692	1,302,469	1,343,774	1,373,484	1,389,888	1,393,622
Health Care & Social Assistance	-	5,209	19,042	45,975	91,038	158,393	249,099	358,638	475,564	583,690	682,915	754,698	793,756	837,844	857,365	880,847	895,299	904,722	908,090	904,681	894,909
Wholesale Trade	-	3,174	11,397	26,932	52,053	88,137	134,594	188,150	242,925	291,704	333,331	360,865	372,583	381,115	380,661	379,793	376,785	371,281	363,722	353,904	342,090
Offices	-	42,490	157,011	373,065	735,294	1,285,638	2,045,301	2,997,090	4,068,582	5,135,357	6,208,382	7,068,152	7,616,751	8,272,840	8,673,181	9,028,016	9,298,711	9,520,126	9,676,479	9,756,286	9,761,940
Retail Trade	-	8,209	29,540	69,591	134,092	226,141	343,196	475,461	606,837	719,165	807,717	860,782	878,945	891,956	883,108	874,612	861,351	844,366	823,370	797,658	767,567
Transportation & Warehousing	-	1,414	5,128	11,958	22,981	38,947	59,698	83,718	108,000	128,789	144,245	152,685	154,587	154,771	150,331	144,881	138,652	131,842	124,625	117,087	109,331
Other Services	-	727	2,642	6,134	11,721	19,720	29,994	41,877	54,201	65,501	76,175	84,026	88,142	92,324	93,894	94,644	94,417	93,499	91,987	89,949	87,508
Total	-	72,916	267,393	634,958	1,244,674	2,155,178	3,385,235	4,888,028	6,533,387	8,122,930	9,677,729	10,884,479	11,614,642	12,457,026	12,942,309	13,388,987	13,714,989	13,965,984	14,124,499	14,175,328	14,122,725
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.4	1.5	3.5	6.9	11.9	18.6	26.6	35.3	43.6	51.7	57.9	61.8	67.0	70.0	71.0	71.8	72.3	72.5	72.3	71.6
Arts, Entertainment and Recreation	-	0.1	0.3	0.8	1.6	2.6	3.9	5.3	6.8	8.1	10.0	11.6	12.8	14.3	15.8	17.4	18.9	20.2	21.6	22.8	24.0
Information & Cultural Industries	-	0.1	0.3	0.7	1.4	2.5	3.8	5.3	7.0	8.5	9.9	11.0	11.6	12.4	12.7	12.9	13.0	13.0	12.9	12.8	12.6
Accommodation & Food Services	-	2.8	10.0	23.4	44.5	72.8	106.2	140.3	170.6	193.8	226.7	249.2	258.0	269.9	281.0	294.1	305.5	314.4	320.4	323.0	322.6
Health Care & Social Assistance	-	0.8	3.0	7.0	13.7	23.1	35.1	48.6	62.0	73.5	86.1	94.7	98.8	104.7	108.4	111.8	114.6	116.8	118.2	118.6	118.0
Wholesale Trade	-	0.7	2.5	5.8	11.1	18.4	27.1	36.4	44.8	51.4	57.7	61.4	62.5	63.8	64.0	63.9	63.6	62.9	61.8	60.3	58.4
Offices	-	8.0	29.2	68.7	133.5	226.2	347.4	489.7	640.6	782.9	948.2	1,074.4	1,147.6	1,251.7	1,324.1	1,381.7	1,433.6	1,478.1	1,512.1	1,533.3	1,541.4
Retail Trade	-	1.8	6.5	15.3	29.2	48.1	70.7	93.9	114.2	129.1	141.4	147.4	148.3	149.0	147.1	145.0	142.6	139.6	135.9	131.4	126.2
Transportation & Warehousing	-	0.4	1.3	3.0	5.8	9.7	14.6	20.0	25.1	29.2	32.9	34.9	35.2	35.6	35.1	34.4	33.5	32.3	31.0	29.5	27.9
Other Services	-	0.2	0.7	1.5	2.9	4.8	7.0	9.5	11.7	13.6	15.8	17.3	18.0	18.9	19.4	19.8	19.9	20.0	19.8	19.5	19.1
Total	-	15.2	55.2	129.9	250.8	420.1	634.4	875.6	1,118.1	1,333.7	1,580.4	1,759.7	1,854.5	1,987.4	2,077.6	2,151.8	2,217.0	2,269.7	2,306.3	2,323.5	2,321.7

Commercial Sector Results by Sub-sector *(continued)*

DSM100 Scenario

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	4,822	19,427	49,300	101,001	175,564	262,298	344,784	405,287	458,408	484,233	493,199	500,270	504,885	506,132	505,288	502,235	497,514	491,356	483,829	474,944
Arts, Entertainment and Recreation	-	1,486	5,719	13,948	26,314	41,515	58,006	75,610	90,824	104,152	116,285	126,146	135,198	144,094	152,670	161,802	170,597	179,102	187,362	195,415	203,291
Information & Cultural Industries	-	1,654	6,579	16,360	32,172	53,016	75,125	94,822	108,303	118,972	123,317	124,321	124,645	124,512	123,954	123,114	121,918	120,386	118,531	116,362	113,890
Accommodation & Food Services	-	13,975	54,908	138,852	276,972	462,284	663,130	881,936	1,053,020	1,164,873	1,259,359	1,336,613	1,401,940	1,448,766	1,472,473	1,481,058	1,477,876	1,468,558	1,455,921	1,441,212	1,425,027
Health Care & Social Assistance	-	9,795	38,959	100,655	206,230	353,348	515,386	668,923	776,313	854,686	896,120	926,619	950,708	966,387	971,865	970,770	963,981	953,553	940,497	925,269	908,111
Wholesale Trade	-	5,966	23,255	58,515	116,195	192,773	273,929	346,971	395,360	423,231	432,892	436,779	436,386	432,580	424,698	414,386	402,077	388,692	374,704	360,347	345,760
Offices	-	79,855	321,064	816,533	1,673,757	2,913,109	4,366,815	5,889,744	7,078,661	8,107,212	8,784,323	9,187,281	9,546,423	9,819,012	9,981,109	10,070,895	10,100,149	10,091,699	10,056,036	9,996,958	9,915,596
Retail Trade	-	15,431	60,249	150,849	297,195	486,818	679,958	841,494	941,495	998,317	1,013,378	1,013,985	1,009,110	997,263	976,425	949,785	918,480	884,614	849,301	813,115	776,416
Transportation & Warehousing	-	2,661	10,493	26,145	51,906	86,363	122,260	151,542	168,318	177,564	176,358	172,158	166,786	160,748	154,144	147,348	140,215	132,822	125,223	117,466	109,599
Other Services	-	1,363	5,360	13,158	25,651	42,091	59,626	76,682	89,041	97,890	102,262	103,578	103,915	103,362	102,017	100,359	98,330	96,052	93,589	90,973	88,226
Total	-	137,008	546,012	1,384,316	2,807,394	4,806,880	7,076,532	9,372,509	11,106,622	12,505,304	13,388,526	13,920,680	14,375,381	14,701,608	14,865,487	14,924,805	14,895,859	14,812,993	14,692,520	14,540,945	14,360,860
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.8	3.0	7.6	15.3	25.8	37.4	49.2	58.2	67.2	73.1	74.6	76.0	76.9	77.3	77.6	77.3	76.8	76.0	75.0	73.8
Arts, Entertainment and Recreation	-	0.2	0.7	1.7	3.3	5.1	7.0	9.4	11.5	13.3	15.2	16.7	18.0	19.3	20.5	21.7	22.8	23.8	24.8	25.8	26.8
Information & Cultural Industries	-	0.2	0.6	1.6	3.1	5.2	7.3	9.4	10.9	12.1	12.8	13.0	13.2	13.3	13.3	13.3	13.3	13.2	13.1	12.9	12.8
Accommodation & Food Services	-	5.2	19.8	48.2	90.6	138.5	182.2	236.0	275.3	294.4	315.7	332.7	347.0	356.2	359.5	359.9	357.0	352.5	347.2	341.5	335.7
Health Care & Social Assistance	-	1.5	6.0	14.9	29.4	47.5	66.1	85.5	99.1	108.9	116.2	120.8	124.9	127.7	128.9	129.3	128.7	127.5	125.9	124.1	122.0
Wholesale Trade	-	1.3	5.0	12.4	23.7	37.1	49.7	61.4	69.1	73.2	75.7	76.5	76.6	76.1	74.6	72.8	70.5	67.9	65.3	62.6	59.9
Offices	-	14.9	58.7	145.5	287.1	472.6	676.2	911.5	1,091.2	1,245.8	1,367.1	1,436.6	1,501.4	1,552.1	1,583.2	1,604.0	1,612.6	1,613.7	1,609.8	1,602.1	1,591.2
Retail Trade	-	3.4	13.2	32.5	62.1	96.1	126.4	151.1	166.5	173.0	176.4	176.3	175.4	173.0	168.7	163.4	157.1	150.2	143.2	136.1	129.2
Transportation & Warehousing	-	0.7	2.6	6.5	12.7	20.4	28.0	34.9	39.1	41.2	41.7	41.3	40.5	39.4	38.0	36.6	35.1	33.4	31.7	30.0	28.3
Other Services	-	0.3	1.3	3.2	6.0	9.4	12.7	16.3	19.0	20.7	21.9	22.4	22.7	22.7	22.4	22.2	21.8	21.3	20.8	20.2	19.7
Total	-	28.4	111.0	274.1	533.3	857.8	1,192.9	1,564.8	1,839.9	2,049.6	2,215.7	2,310.8	2,395.5	2,456.6	2,486.4	2,500.7	2,496.2	2,480.5	2,457.8	2,430.3	2,399.2

DSM100 Plus Standards

Commercial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Educational Services	-	4,822	19,427	390,423	471,295	482,474	493,773	502,998	509,278	513,128	515,295	516,225	516,097	514,959	512,798	510,421	506,890	502,163	496,190	488,932	480,354
Arts, Entertainment and Recreation	-	1,486	5,719	83,333	94,748	104,663	114,922	125,100	134,866	144,107	152,837	161,105	168,961	176,457	183,643	191,442	199,022	206,433	213,717	218,347	223,144
Information & Cultural Industries	-	1,654	6,579	104,228	116,664	118,729	120,695	122,389	123,709	124,651	125,249	125,529	125,500	125,162	124,515	123,651	122,467	120,964	119,146	117,020	114,593
Accommodation & Food Services	-	13,975	54,908	1,023,800	1,223,261	1,304,170	1,391,269	1,460,618	1,502,447	1,522,529	1,529,723	1,529,828	1,525,729	1,518,747	1,509,509	1,502,058	1,492,470	1,481,008	1,467,886	1,453,308	1,437,487
Health Care & Social Assistance	-	9,795	38,959	789,346	871,325	905,482	941,551	970,570	988,729	998,005	1,001,592	1,001,579	998,970	994,185	987,386	980,410	971,322	960,183	947,043	931,973	915,069
Wholesale Trade	-	5,966	23,255	453,816	481,374	487,034	492,919	495,208	492,506	485,895	476,861	466,351	454,836	442,547	429,615	416,900	403,639	389,924	375,841	361,474	346,906
Offices	-	79,855	321,064	6,471,613	8,204,168	8,624,345	9,071,257	9,444,896	9,703,505	9,870,032	9,980,430	10,057,834	10,113,155	10,150,695	10,171,790	10,194,873	10,199,123	10,184,175	10,149,371	10,094,036	10,017,625
Retail Trade	-	15,431	60,249	1,065,312	1,131,290	1,141,205	1,150,964	1,152,750	1,143,859	1,126,631	1,104,120	1,078,217	1,049,850	1,019,485	987,407	955,399	921,987	887,415	851,919	815,735	779,104
Transportation & Warehousing	-	2,661	10,493	193,034	204,662	201,758	198,707	195,110	190,781	185,789	180,276	174,346	168,062	161,461	154,570	147,646	140,466	133,061	125,466	117,719	109,864
Other Services	-	1,363	5,360	88,276	105,550	107,445	109,470	110,875	111,308	110,904	109,933	108,587	106,973	105,141	103,122	101,166	99,029	96,727	94,275	91,685	88,970
Total	-	137,008	546,012	10,663,180	12,904,338	13,477,303	14,085,527	14,580,513	14,900,987	15,081,671	15,176,317	15,219,600	15,228,132	15,208,840	15,164,355	15,123,966	15,056,416	14,962,054	14,840,855	14,690,228	14,513,117
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Educational Services	-	0.8	3.0	50.9	72.4	74.0	76.1	77.9	79.2	80.0	80.7	80.9	80.9	80.7	80.3	80.0	79.6	79.1	78.3	77.4	76.2
Arts, Entertainment and Recreation	-	0.2	0.7	8.7	12.6	13.9	15.4	16.9	18.3	19.5	20.7	21.7	22.7	23.6	24.4	25.4	26.4	27.3	28.2	28.9	29.5
Information & Cultural Industries	-	0.2	0.6	9.4	11.7	12.0	12.3	12.6	12.9	13.1	13.3	13.4	13.5	13.5	13.5	13.5	13.5	13.4	13.3	13.1	13.0
Accommodation & Food Services	-	5.2	19.8	234.2	323.9	340.9	361.8	378.5	388.2	391.5	392.7	390.3	386.2	381.2	375.5	371.4	366.7	361.6	356.2	350.8	345.4
Health Care & Social Assistance	-	1.5	6.0	89.8	115.5	120.0	125.8	130.6	133.7	135.2	136.4	136.3	135.8	135.0	133.8	133.0	131.8	130.5	128.9	127.1	125.1
Wholesale Trade	-	1.3	5.0	72.1	86.4	87.2	88.8	89.7	89.4	88.2	86.7	84.6	82.1	79.4	76.6	74.1	71.5	68.8	66.1	63.4	60.7
Offices	-	14.9	58.7	893.7	1,303.8	1,368.6	1,447.8	1,515.8	1,564.3	1,593.9	1,619.3	1,632.2	1,640.2	1,644.5	1,645.9	1,651.3	1,653.6	1,652.9	1,649.3	1,642.9	1,633.7
Retail Trade	-	3.4	13.2	177.2	203.1	204.1	206.6	207.4	205.9	202.3	198.4	192.8	186.5	179.8	172.7	166.0	159.0	151.9	144.8	137.7	130.8
Transportation & Warehousing	-	0.7	2.6	40.1	47.8	47.5	47.5	47.3	46.7	45.7	44.7	43.4	41.9	40.3	38.6	37.1	35.5	33.8	32.1	30.4	28.6
Other Services	-	0.3	1.3	16.6	23.1	23.6	24.3	24.8	25.1	25.1	25.0	24.6	24.2	23.7	23.2	22.8	22.3	21.8	21.3	20.8	20.2
Total	-	28.4	111.0	1,592.8	2,200.2	2,291.8	2,406.3	2,501.4	2,563.9	2,594.5	2,618.0	2,620.3	2,614.1	2,601.7	2,584.5	2,574.5	2,559.9	2,541.1	2,518.6	2,492.4	2,463.3

Figure 13. Industrial Sector Achievable Potential Scenarios (Electricity Sales)

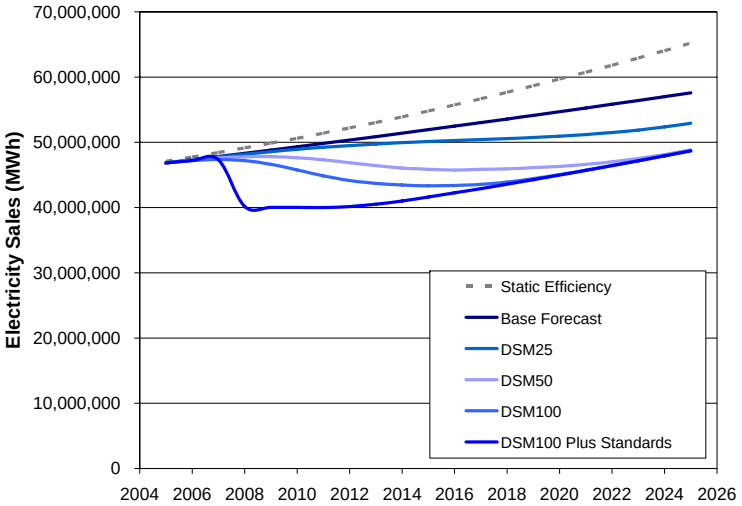


Figure 14. Industrial Sector Achievable Potential Scenarios (Peak Demand)

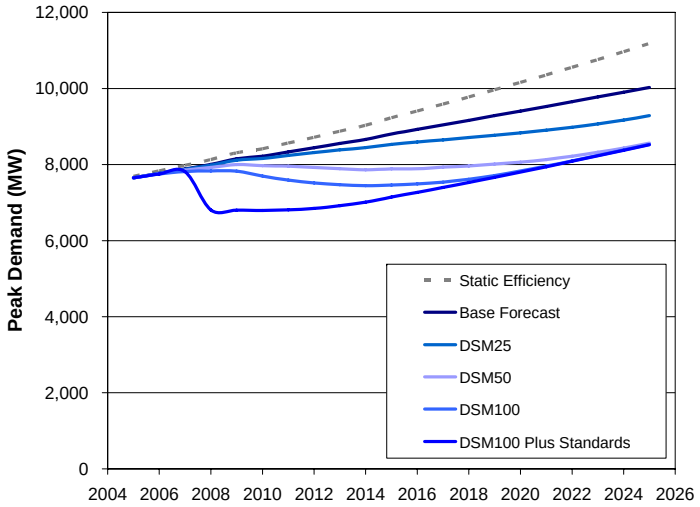


Figure 15. 2015 Industrial Sector Achievable Potential by End Use (DSM50, Electricity Sales)

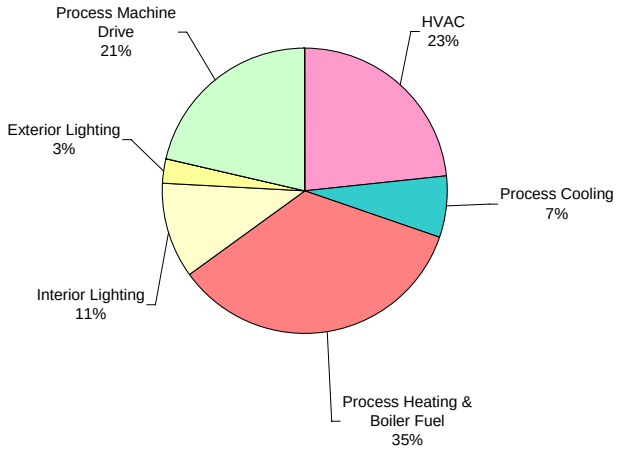


Figure 16. 2015 Industrial Sector Achievable Potential by End Use (DSM50, Peak Demand)

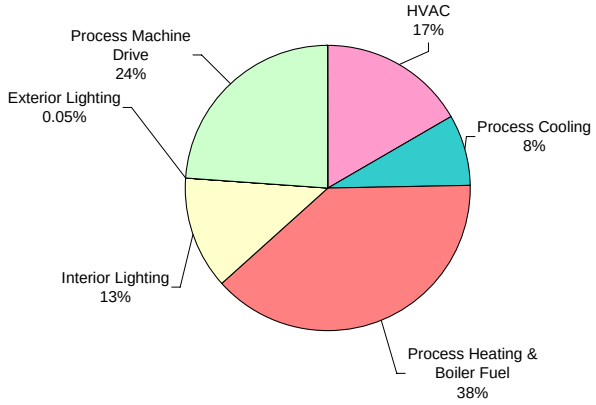


Figure 17. 2015 Industrial Sector Achievable Potential by Sub-sector (DSM50, Electricity Sales)

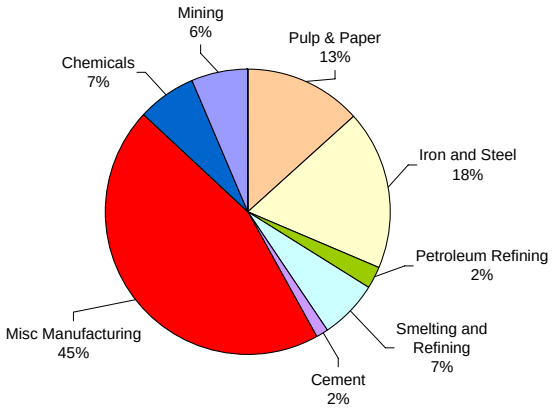


Figure 18. 2015 Industrial Sector Achievable Potential by Sub-sector (DSM50, Peak Demand)

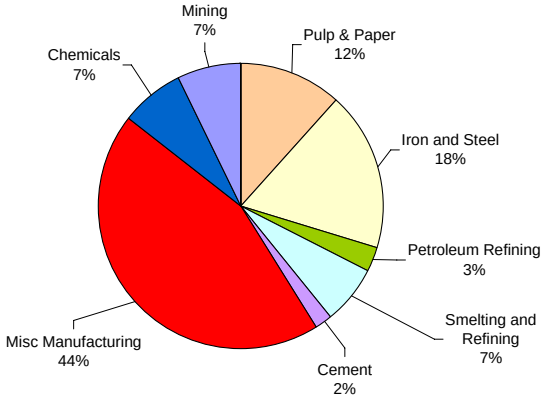


Table 5. Industrial Sector Results by End Use

DSM25 Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	4,521	14,826	32,219	57,949	93,120	138,616	195,053	262,749	341,602	430,820	528,465	630,949	732,780	826,866	912,667	979,371	1,021,965	1,050,351	1,050,759	1,030,753
Process Cooling	-	791	2,683	6,060	11,386	19,198	30,085	44,638	63,368	86,584	114,228	145,702	179,732	214,335	246,987	274,998	296,040	308,651	312,502	308,317	297,502
Process Heating & Boiler Fuel	-	2,346	8,019	18,296	34,802	59,573	95,093	144,301	210,529	297,321	408,099	545,601	711,087	903,373	1,117,855	1,345,887	1,574,960	1,790,042	1,976,078	2,121,032	2,218,324
Interior Lighting	-	1,006	3,504	7,690	14,236	23,953	37,693	56,385	80,965	112,250	150,779	196,627	249,214	307,131	368,065	428,918	486,084	536,108	576,206	604,701	621,713
Exterior Lighting	-	182	626	1,431	2,722	4,649	7,394	11,176	16,255	22,925	31,485	42,186	55,144	70,270	87,238	105,607	124,612	143,341	160,838	176,212	188,114
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	9,924	32,398	69,924	124,420	196,587	285,154	386,188	492,743	595,220	682,678	745,005	775,325	771,709	737,394	679,445	606,552	526,987	447,372	372,322	304,652
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	18,771	62,057	135,619	245,515	397,079	594,033	837,742	1,126,610	1,455,902	1,818,089	2,203,586	2,601,450	2,999,597	3,384,405	3,747,522	4,067,619	4,327,093	4,523,347	4,633,343	4,661,058
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	0.5	1.5	3.3	5.9	9.5	14.0	19.6	26.2	34.1	43.2	53.3	64.4	75.9	87.1	98.0	107.5	115.1	122.0	126.0	127.5
Process Cooling	-	0.1	0.5	1.1	2.0	3.4	5.4	8.0	11.3	15.5	20.6	26.4	32.7	39.1	45.3	50.6	54.7	57.3	58.3	57.8	56.0
Process Heating & Boiler Fuel	-	0.4	1.3	3.0	5.7	9.8	15.6	23.7	34.7	49.2	67.8	90.9	118.9	151.6	188.3	227.5	267.2	304.7	337.6	363.7	381.7
Interior Lighting	-	0.2	0.6	1.3	2.5	4.2	6.6	9.9	14.3	19.9	26.9	35.4	45.1	56.0	67.6	79.4	90.6	100.7	109.1	115.3	119.4
Exterior Lighting	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	1.6	5.2	11.3	20.3	32.2	46.9	63.7	81.5	98.9	114.2	125.4	131.4	131.8	126.9	117.9	106.1	93.1	79.8	67.2	55.6
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	2.8	9.1	20.0	36.5	59.0	88.4	124.9	168.2	217.6	272.7	331.5	392.7	454.5	515.4	573.6	626.5	671.3	707.2	730.4	740.7

DSM50 Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	15,169	53,406	123,351	232,723	386,683	585,473	818,725	1,059,111	1,267,128	1,423,168	1,504,819	1,532,645	1,648,292	1,735,550	1,851,387	1,984,062	2,111,317	2,209,537	2,266,229	2,283,772
Process Cooling	-	2,689	9,988	24,707	50,508	91,200	148,771	220,276	295,792	361,279	406,298	429,435	436,088	449,522	445,992	442,914	439,287	433,432	423,849	410,089	392,780
Process Heating & Boiler Fuel	-	7,992	30,081	75,888	159,750	301,104	522,003	838,497	1,244,509	1,696,345	2,118,579	2,441,825	2,642,254	2,742,037	2,778,850	2,846,310	2,841,473	2,834,698	2,823,352	2,803,276	2,770,601
Interior Lighting	-	3,418	13,049	31,372	63,548	115,794	193,196	296,511	418,368	542,946	651,860	732,767	783,548	819,931	836,098	831,628	827,967	814,089	797,128	777,175	756,041
Exterior Lighting	-	621	2,344	5,918	12,429	23,314	40,193	64,357	95,798	132,123	168,363	198,741	219,629	232,340	237,664	242,145	240,858	239,871	239,208	238,691	236,062
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	33,368	116,982	266,739	487,172	757,402	1,026,252	1,232,139	1,338,804	1,351,330	1,299,062	1,424,463	1,555,260	1,747,788	1,972,522	2,178,656	2,320,778	2,385,789	2,392,113	2,367,916	2,334,459
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	63,256	225,850	527,974	1,006,130	1,675,498	2,515,888	3,470,505	4,452,382	5,351,151	6,067,329	6,732,051	7,169,425	7,639,910	8,006,676	8,393,040	8,654,425	8,819,197	8,885,187	8,863,376	8,773,714
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
HVAC	-	1.6	5.5	12.6	23.6	38.7	58.4	82.1	107.8	132.1	153.9	168.8	177.7	201.0	222.6	244.2	270.0	297.2	322.1	341.8	355.3
Process Cooling	-	0.5	1.8	4.4	9.0	16.2	26.5	39.4	53.0	65.0	73.5	78.1	79.7	82.7	82.4	82.1	81.8	81.0	79.5	77.2	74.2
Process Heating & Boiler Fuel	-	1.3	4.9	12.3	26.1	49.4	85.8	138.1	205.7	281.1	352.9	408.6	444.1	462.7	470.7	484.7	485.4	485.7	485.3	483.3	479.0
Interior Lighting	-	0.6	2.3	5.5	11.1	20.3	34.0	52.4	74.5	97.3	118.0	133.8	144.3	152.7	157.2	157.2	157.4	155.6	153.1	150.1	146.8
Exterior Lighting	-	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	5.4	18.9	43.3	79.7	124.2	168.9	203.5	222.2	225.3	218.6	242.3	265.7	299.5	338.8	375.0	400.4	412.7	414.9	411.7	406.8
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	9.3	33.3	78.1	149.6	248.8	373.6	515.7	663.4	801.2	917.3	1,032.2	1,112.1	1,199.3	1,272.4	1,343.9	1,395.6	1,432.8	1,455.5	1,464.8	1,462.8

Industrial Sector Results by End Use *(continued)*

DSM100 Scenario

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	28,299	106,844	259,708	503,419	828,465	1,170,780	1,449,010	1,603,740	1,810,943	1,941,933	2,096,070	2,262,341	2,389,353	2,454,795	2,481,235	2,477,296	2,457,383	2,428,854	2,395,051	2,357,505
Process Cooling	-	5,096	20,888	56,556	122,398	218,884	323,509	402,941	444,717	479,855	483,085	488,379	492,798	492,671	486,977	477,020	464,218	449,324	432,665	414,416	394,732
Process Heating & Boiler Fuel	-	15,195	63,662	179,384	416,194	829,254	1,407,283	2,008,032	2,451,349	2,689,020	2,876,514	2,897,697	2,922,158	2,943,427	2,953,436	2,949,663	2,934,448	2,910,290	2,878,222	2,838,295	2,790,171
Interior Lighting	-	6,473	27,276	72,061	156,949	291,735	460,562	621,613	738,285	819,169	853,621	861,139	857,625	853,018	846,942	838,881	827,967	814,089	797,128	777,175	756,041
Exterior Lighting	-	1,180	4,949	13,917	32,132	63,801	108,877	158,134	197,633	223,529	242,248	245,515	246,168	245,619	244,106	242,536	241,294	240,358	239,753	239,300	236,729
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	62,389	233,764	546,639	954,901	1,317,020	1,518,251	1,565,151	1,735,669	1,917,609	2,200,184	2,492,695	2,681,899	2,740,137	2,713,763	2,651,445	2,579,504	2,509,149	2,445,060	2,389,390	2,343,175
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	118,631	457,382	1,128,265	2,185,993	3,549,159	4,989,261	6,204,880	7,171,393	7,940,126	8,597,586	9,081,494	9,462,989	9,664,226	9,700,018	9,640,781	9,524,727	9,380,594	9,221,683	9,053,627	8,878,353

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	2.9	10.9	26.2	50.4	82.5	118.5	151.9	175.2	212.5	246.2	273.7	305.8	335.1	356.4	371.1	379.4	383.4	384.8	384.6	383.2
Process Cooling	-	0.9	3.7	10.0	21.7	38.9	57.7	72.1	79.9	86.6	87.8	89.2	90.3	90.7	90.0	88.4	86.4	83.9	81.1	78.0	74.5
Process Heating & Boiler Fuel	-	2.5	10.3	29.2	68.2	136.0	231.4	331.2	405.6	446.3	481.5	486.8	492.7	498.0	501.3	502.3	501.2	498.7	494.7	489.3	482.4
Interior Lighting	-	1.1	4.7	12.5	27.5	51.2	81.3	110.5	132.2	148.4	157.1	159.4	159.6	159.6	159.3	158.6	157.4	155.6	153.1	150.1	146.8
Exterior Lighting	-	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	10.0	37.8	88.8	156.5	216.2	250.1	258.9	289.2	320.7	371.2	422.3	456.1	467.7	464.9	455.9	444.9	434.1	424.2	415.6	408.4
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	17.4	67.4	166.7	324.3	525.0	739.3	924.9	1,082.7	1,215.1	1,344.5	1,432.0	1,505.2	1,551.8	1,572.6	1,577.0	1,570.1	1,556.5	1,538.7	1,518.3	1,496.1

DSM100 Plus Standards

Industrial Electric by End Use Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	28,299	106,844	1,780,980	2,073,940	2,231,344	2,403,559	2,538,996	2,615,462	2,644,668	2,646,165	2,633,224	2,612,533	2,587,052	2,558,027	2,536,350	2,511,168	2,482,856	2,451,554	2,417,367	2,380,456
Process Cooling	-	5,096	20,888	491,212	499,372	509,839	519,902	526,210	527,849	526,001	521,902	516,146	508,905	500,178	489,914	478,058	464,572	449,448	432,711	414,434	394,739
Process Heating & Boiler Fuel	-	15,195	63,662	2,782,459	2,818,421	2,859,177	2,898,979	2,930,749	2,952,503	2,966,615	2,975,527	2,980,305	2,981,082	2,977,580	2,969,359	2,955,904	2,936,661	2,911,053	2,878,492	2,838,397	2,790,213
Interior Lighting	-	6,473	27,276	766,685	843,371	849,946	855,876	860,584	863,620	864,718	863,929	861,603	858,154	853,616	847,616	839,634	828,803	815,011	798,139	778,276	757,240
Exterior Lighting	-	1,180	4,949	224,850	239,781	240,187	240,204	240,382	241,100	242,504	244,335	245,957	246,643	246,125	244,642	243,104	241,899	241,005	240,446	240,044	237,521
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	62,389	233,764	2,114,214	2,313,904	2,604,398	2,899,844	3,093,780	3,159,772	3,140,266	3,079,814	3,002,333	2,918,024	2,831,463	2,745,366	2,661,886	2,582,959	2,510,332	2,445,486	2,389,553	2,343,240
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	118,631	457,382	8,160,400	8,788,788	9,294,891	9,818,364	10,190,700	10,360,305	10,384,772	10,331,672	10,239,568	10,125,341	9,996,015	9,854,924	9,714,936	9,566,063	9,409,703	9,246,827	9,078,071	8,903,409

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
HVAC	-	2.9	10.9	179.5	259.7	285.1	316.8	345.7	367.0	380.0	388.8	392.7	394.3	394.5	393.6	394.0	393.7	393.0	391.9	390.3	388.4
Process Cooling	-	0.9	3.7	86.8	89.1	90.8	92.9	94.4	95.0	94.9	94.9	94.3	93.3	92.1	90.5	88.6	86.5	84.0	81.1	78.0	74.6
Process Heating & Boiler Fuel	-	2.5	10.3	453.6	463.6	469.5	477.7	484.4	489.6	493.2	498.1	500.7	502.6	503.8	504.0	503.3	501.6	498.8	494.7	489.3	482.4
Interior Lighting	-	1.1	4.7	131.1	151.2	152.1	153.9	155.5	156.8	157.6	159.1	159.5	159.7	159.7	159.5	158.8	157.6	155.8	153.3	150.3	147.0
Exterior Lighting	-	0.0	0.0	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Other Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Machine Drive	-	10.0	37.8	344.6	381.5	429.0	479.7	513.7	526.8	525.2	519.1	508.4	496.2	483.4	470.4	457.7	445.6	434.3	424.3	415.6	408.4
Electrochemical Process	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	17.4	67.4	1,196.3	1,345.8	1,427.1	1,521.6	1,594.4	1,635.9	1,651.7	1,660.7	1,656.4	1,647.0	1,634.2	1,618.8	1,603.2	1,585.8	1,566.7	1,546.2	1,524.4	1,501.6

Table 6. Industrial Sector Results by Sub-sector

DSM25 Scenario

Industrial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	4,101	13,454	29,153	52,181	83,132	121,943	167,644	218,223	270,700	321,511	367,146	404,864	433,183	451,926	462,409	465,444	462,067	454,007	440,933	423,978
Iron and Steel	-	2,149	7,182	15,931	29,345	48,433	74,203	107,596	149,425	200,312	260,655	330,557	409,687	497,022	590,481	686,839	781,093	867,404	940,405	994,984	1,028,980
Petroleum Refining	-	835	2,737	5,930	10,609	16,885	24,731	33,924	44,018	54,358	64,163	72,665	79,265	83,648	85,803	86,017	84,589	81,867	78,278	73,973	69,242
Smelting and Refining	-	784	2,620	5,812	10,707	17,672	27,076	39,265	54,533	73,111	95,144	120,669	149,568	181,463	215,595	250,784	285,199	316,709	343,353	363,267	375,666
Cement	-	403	1,324	2,878	5,172	8,278	12,212	16,906	22,199	27,839	33,519	38,938	43,859	48,151	51,778	54,785	57,162	58,871	59,887	60,099	59,521
Misc Manufacturing	-	7,558	25,041	54,770	99,360	161,296	242,660	344,942	468,830	613,999	778,897	960,454	1,153,754	1,351,767	1,545,370	1,729,571	1,890,293	2,017,616	2,113,869	2,164,663	2,174,599
Chemicals	-	1,726	5,680	12,355	22,218	35,610	52,635	73,062	96,264	121,217	146,612	171,051	193,277	212,331	227,603	239,057	246,367	249,497	249,052	244,754	237,304
Mining	-	1,214	4,019	8,789	15,924	25,773	38,574	54,402	73,119	94,365	117,587	142,105	167,177	192,032	215,848	238,061	257,473	273,063	284,497	290,669	291,768
Total	-	18,771	62,057	135,619	245,515	397,079	594,033	837,742	1,126,610	1,455,902	1,818,089	2,203,586	2,601,450	2,999,597	3,384,405	3,747,522	4,067,619	4,327,093	4,523,347	4,633,343	4,661,058
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pulp & Paper	-	0.5	1.8	3.9	7.0	11.2	16.4	22.6	29.4	36.5	43.5	49.7	54.8	58.6	61.0	62.3	62.6	62.1	61.0	59.2	57.0
Iron and Steel	-	0.3	1.0	2.3	4.3	7.1	10.9	15.9	22.1	29.7	38.9	49.6	61.7	75.3	89.8	105.0	120.0	133.9	145.9	155.1	161.2
Petroleum Refining	-	0.1	0.5	1.0	1.9	3.0	4.4	6.0	7.9	9.7	11.5	13.1	14.3	15.1	15.5	15.5	15.3	14.8	14.1	13.3	12.5
Smelting and Refining	-	0.1	0.4	0.8	1.6	2.6	4.0	5.8	8.1	10.9	14.2	18.1	22.5	27.5	32.8	38.3	43.8	48.9	53.3	56.6	58.8
Cement	-	0.1	0.2	0.5	0.9	1.5	2.2	3.0	4.0	5.0	6.0	7.1	8.0	8.8	9.5	10.0	10.5	10.8	11.1	11.1	11.1
Misc Manufacturing	-	1.1	3.6	7.8	14.3	23.2	35.0	49.8	67.7	88.9	113.2	140.2	169.3	199.7	230.2	259.9	287.0	310.0	328.9	341.1	347.0
Chemicals	-	0.3	1.0	2.1	3.8	6.1	9.1	12.6	16.7	21.0	25.4	29.7	33.6	36.9	39.6	41.5	42.8	43.4	43.4	42.8	41.6
Mining	-	0.2	0.7	1.5	2.7	4.3	6.5	9.2	12.3	15.9	19.9	24.1	28.5	32.8	37.0	40.9	44.4	47.4	49.6	51.0	51.5
Total	-	2.8	9.1	20.0	36.5	59.0	88.4	124.9	168.2	217.6	272.7	331.5	392.7	454.5	515.4	573.6	626.5	671.3	707.2	730.4	740.7

DSM50 Scenario

Industrial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	13,800	48,711	112,003	207,647	331,087	466,787	593,529	694,731	763,598	801,159	883,952	951,969	1,042,003	1,132,753	1,218,857	1,279,630	1,311,555	1,319,562	1,312,141	1,296,760
Iron and Steel	-	7,271	26,427	63,477	125,467	219,147	349,207	516,078	712,113	916,984	1,100,284	1,253,756	1,352,644	1,418,382	1,457,617	1,506,953	1,521,695	1,527,704	1,525,235	1,514,688	1,496,508
Petroleum Refining	-	2,810	9,909	22,770	42,139	66,930	93,705	117,830	135,783	146,412	150,457	164,839	177,142	194,231	211,890	228,271	239,632	245,007	245,566	243,226	239,574
Smelting and Refining	-	2,652	9,641	23,160	45,782	79,976	127,461	188,399	259,993	334,801	401,703	457,703	493,780	517,686	532,077	550,129	555,544	557,769	556,892	553,062	546,439
Cement	-	1,356	4,804	11,114	20,783	33,543	48,120	62,674	75,657	86,115	93,440	104,442	112,967	122,105	130,840	139,419	144,625	147,076	147,302	146,137	144,245
Misc Manufacturing	-	25,460	91,101	213,442	409,486	691,046	1,058,602	1,494,810	1,958,724	2,389,200	2,735,513	3,001,833	3,158,529	3,356,146	3,494,983	3,646,814	3,773,206	3,870,419	3,927,404	3,939,271	3,911,412
Chemicals	-	5,813	20,616	47,737	89,465	144,968	209,012	273,264	329,547	372,155	398,899	436,829	464,892	501,859	535,518	567,546	589,923	601,209	602,869	597,805	588,817
Mining	-	4,094	14,641	34,270	65,361	108,800	162,995	223,920	285,835	341,885	385,874	428,696	457,502	487,498	510,998	535,052	550,168	558,460	560,357	557,046	549,958
Total	-	63,256	225,850	527,974	1,006,130	1,675,498	2,515,888	3,470,505	4,452,382	5,351,151	6,067,329	6,732,051	7,169,425	7,639,910	8,006,676	8,393,040	8,654,425	8,819,197	8,885,187	8,863,376	8,773,714
Aggregate Demand (MW)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pulp & Paper	-	1.8	6.5	15.0	27.9	44.4	62.5	79.2	92.4	101.2	106.4	118.9	129.2	142.6	156.3	169.1	178.2	183.3	185.1	184.8	183.4
Iron and Steel	-	1.0	3.8	9.2	18.4	32.2	51.5	76.4	106.0	137.1	165.8	190.3	206.5	217.6	224.8	233.6	236.7	238.5	239.1	238.4	236.4
Petroleum Refining	-	0.5	1.7	4.0	7.5	11.9	16.6	20.9	24.0	25.9	26.7	29.5	32.0	35.3	38.9	42.1	44.4	45.6	45.9	45.6	45.1
Smelting and Refining	-	0.4	1.4	3.4	6.7	11.8	18.8	27.9	38.7	50.1	60.5	69.4	75.4	79.4	82.0	85.3	86.4	87.1	87.3	87.0	86.3
Cement	-	0.2	0.8	2.0	3.7	6.0	8.6	11.2	13.5	15.4	16.8	19.0	20.6	22.5	24.2	25.9	27.0	27.6	27.7	27.6	27.3
Misc Manufacturing	-	3.6	13.0	30.6	59.0	99.5	152.4	215.8	284.5	350.4	407.5	456.0	488.1	528.1	560.4	590.9	618.0	641.2	659.1	670.3	674.7
Chemicals	-	1.0	3.5	8.2	15.4	24.9	35.9	46.8	56.3	63.5	68.3	75.7	81.3	88.6	95.5	101.9	106.5	109.2	110.1	109.8	108.8
Mining	-	0.7	2.4	5.7	11.0	18.2	27.3	37.5	48.0	57.5	65.4	73.5	79.2	85.2	90.2	95.1	98.3	100.4	101.3	101.4	100.7
Total	-	9.3	33.3	78.1	149.6	248.8	373.6	515.7	663.4	801.2	917.3	1,032.2	1,112.1	1,199.3	1,272.4	1,343.9	1,395.6	1,432.8	1,455.5	1,464.8	1,462.8

Industrial Sector Results by Sub-sector *(continued)*

DSM100 Scenario

Industrial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	25,829	97,791	232,954	422,748	622,157	782,428	883,531	1,000,851	1,110,473	1,237,320	1,356,294	1,438,800	1,471,342	1,467,655	1,446,685	1,418,695	1,388,999	1,359,904	1,332,432	1,307,001
Iron and Steel	-	13,703	54,380	140,847	292,902	520,296	803,644	1,078,555	1,291,341	1,420,198	1,529,382	1,570,378	1,602,708	1,620,230	1,623,044	1,615,361	1,600,866	1,582,105	1,560,183	1,535,438	1,507,855
Petroleum Refining	-	5,259	19,886	47,275	85,269	123,929	152,896	168,830	189,344	209,081	232,941	256,349	272,036	277,481	275,805	270,840	264,664	258,276	252,102	246,338	241,073
Smelting and Refining	-	4,999	19,841	51,395	106,903	189,946	293,434	393,794	471,419	518,290	558,233	573,242	585,089	591,521	592,573	589,788	584,511	577,674	569,681	560,656	550,593
Cement	-	2,541	9,678	23,318	43,114	65,326	85,398	100,226	115,486	127,504	141,188	152,200	159,709	162,529	162,002	159,832	156,986	153,945	150,913	147,977	145,169
Misc Manufacturing	-	47,726	184,576	458,812	906,726	1,514,556	2,181,834	2,755,769	3,161,408	3,514,952	3,767,331	3,965,615	4,142,253	4,255,147	4,294,397	4,288,302	4,250,245	4,194,819	4,129,147	4,056,342	3,977,516
Chemicals	-	10,892	41,547	100,352	186,488	283,725	369,382	428,323	483,986	534,054	583,642	629,288	661,373	674,104	672,098	662,683	649,852	635,813	621,542	607,478	593,812
Mining	-	7,682	29,685	73,311	141,843	229,224	320,246	395,852	457,558	505,574	547,549	578,128	601,021	611,871	612,445	607,290	598,907	588,962	578,210	566,965	555,335
Total	-	118,631	457,382	1,128,265	2,185,993	3,549,159	4,989,261	6,204,880	7,171,393	7,940,126	8,597,586	9,081,494	9,462,989	9,664,226	9,700,018	9,640,781	9,524,727	9,380,594	9,221,683	9,053,627	8,878,353

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	3.4	13.0	31.1	56.5	82.7	103.4	116.4	132.9	148.5	168.1	185.5	197.9	203.4	203.9	201.9	198.9	195.5	192.0	188.7	185.7
Iron and Steel	-	2.0	7.9	20.5	43.0	76.7	119.0	160.6	193.4	213.7	232.7	239.9	245.9	249.7	251.3	251.2	249.9	247.9	245.4	242.3	238.7
Petroleum Refining	-	0.9	3.5	8.3	15.1	21.8	26.9	29.6	33.5	37.2	42.0	46.6	49.7	51.0	51.0	50.3	49.4	48.3	47.4	46.4	45.6
Smelting and Refining	-	0.7	2.9	7.5	15.7	28.0	43.4	58.6	70.6	78.0	84.9	87.6	89.8	91.2	91.7	91.7	91.3	90.5	89.6	88.5	87.2
Cement	-	0.4	1.7	4.1	7.7	11.6	15.2	17.8	20.7	22.9	25.7	27.9	29.4	30.1	30.1	29.9	29.4	29.0	28.5	28.0	27.6
Misc Manufacturing	-	6.8	26.4	65.8	130.5	217.5	315.2	403.1	471.6	536.4	593.5	632.0	668.7	696.8	713.7	722.3	724.0	721.2	715.5	707.8	698.7
Chemicals	-	1.9	7.1	17.2	32.0	48.4	62.8	72.6	82.8	92.2	102.5	111.4	117.9	121.0	121.4	120.5	118.8	116.8	114.6	112.4	110.3
Mining	-	1.3	4.9	12.2	23.8	38.2	53.4	66.2	77.3	86.3	95.1	101.2	105.9	108.6	109.5	109.3	108.5	107.2	105.7	104.1	102.4
Total	-	17.4	67.4	166.7	324.3	525.0	739.3	924.9	1,082.7	1,215.1	1,344.5	1,432.0	1,505.2	1,551.8	1,572.6	1,577.0	1,570.1	1,556.5	1,538.7	1,518.3	1,496.1

DSM100 Plus Standards

Industrial Electric by Building Type Aggregate Energy (MWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	25,829	97,791	1,174,354	1,281,489	1,400,779	1,522,766	1,605,219	1,636,933	1,634,037	1,613,980	1,586,286	1,555,038	1,522,020	1,488,229	1,455,262	1,422,869	1,391,634	1,362,042	1,334,456	1,309,054
Iron and Steel	-	13,703	54,380	1,473,678	1,523,096	1,571,730	1,620,875	1,656,139	1,673,500	1,678,171	1,675,870	1,669,659	1,660,744	1,649,519	1,636,091	1,620,821	1,603,290	1,583,430	1,561,139	1,536,287	1,508,695
Petroleum Refining	-	5,259	19,886	223,289	242,594	266,172	290,205	306,217	312,016	310,889	306,351	300,307	293,569	286,494	279,286	272,203	265,275	258,629	252,372	246,586	241,321
Smelting and Refining	-	4,999	19,841	537,755	555,841	573,645	591,636	604,550	610,917	612,642	611,819	609,566	606,325	602,241	597,351	591,790	585,403	578,164	570,037	560,973	550,907
Cement	-	2,541	9,678	135,013	144,259	155,559	167,056	174,804	177,784	177,528	175,667	173,081	170,141	167,005	163,762	160,519	157,286	154,112	151,036	148,088	145,280
Misc Manufacturing	-	47,726	184,576	3,535,608	3,879,237	4,085,755	4,303,694	4,466,095	4,548,874	4,571,541	4,560,158	4,530,666	4,490,411	4,442,469	4,388,166	4,336,534	4,279,064	4,216,175	4,148,093	4,074,963	3,996,680
Chemicals	-	10,892	41,547	559,457	604,516	651,280	699,120	731,563	744,114	742,929	734,761	723,322	710,201	696,083	681,337	666,685	651,880	637,138	622,638	608,525	594,877
Mining	-	7,682	29,685	521,247	557,756	589,970	623,011	646,112	656,167	657,035	653,066	646,681	638,912	630,184	620,702	611,122	600,996	590,422	579,470	568,193	556,595
Total	-	118,631	457,382	8,160,400	8,788,788	9,294,891	9,818,364	10,190,700	10,360,305	10,384,772	10,331,672	10,239,568	10,125,341	9,996,015	9,854,924	9,714,936	9,566,063	9,409,703	9,246,827	9,078,071	8,903,409

Aggregate Demand (MW)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Pulp & Paper	-	3.4	13.0	152.1	170.4	186.5	204.2	216.7	222.3	222.8	221.9	219.1	215.7	211.9	207.9	203.9	200.0	196.2	192.5	189.1	186.0
Iron and Steel	-	2.0	7.9	216.8	227.3	234.3	242.7	249.0	252.8	254.4	256.0	256.2	255.8	255.1	253.9	252.4	250.6	248.3	245.6	242.5	238.9
Petroleum Refining	-	0.9	3.5	38.6	42.8	47.1	51.7	54.9	56.2	56.2	55.9	55.0	54.0	52.9	51.8	50.7	49.5	48.5	47.4	46.5	45.6
Smelting and Refining	-	0.7	2.9	79.1	83.0	85.5	88.6	90.9	92.3	92.9	93.5	93.5	93.4	93.1	92.7	92.2	91.5	90.7	89.7	88.5	87.2
Cement	-	0.4	1.7	23.7	25.7	27.8	30.0	31.5	32.2	32.3	32.2	31.9	31.5	31.0	30.5	30.0	29.5	29.0	28.5	28.1	27.6
Misc Manufacturing	-	6.8	26.4	506.9	597.9	633.2	676.0	711.5	734.6	746.3	754.4	755.7	754.2	750.9	746.1	741.6	735.9	729.1	721.4	712.6	703.0
Chemicals	-	1.9	7.1	93.4	103.9	112.2	121.5	128.1	131.2	131.6	131.3	130.0	128.2	126.2	124.0	121.8	119.5	117.2	114.9	112.7	110.6
Mining	-	1.3	4.9	85.9	94.8	100.5	106.9	111.8	114.3	115.1	115.5	115.0	114.2	113.1	111.9	110.6	109.2	107.7	106.1	104.4	102.7
Total	-	17.4	67.4	1,196.3	1,345.8	1,427.1	1,521.6	1,594.4	1,635.9	1,651.7	1,660.7	1,656.4	1,647.0	1,634.2	1,618.8	1,603.2	1,585.8	1,566.7	1,546.2	1,524.4	1,501.6

Appendix F

Program Cost Details

SUMMARY COSTS

Minimally Aggressive

Total Programs Cost of Electric Savings ($1,000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 12,859	$ 30,381	$ 52,027	$ 79,736	$ 113,846	$ 154,021	$ 199,527	$ 249,157	$ 300,347	$ 349,828	$ 393,476	$ 426,517	$ 444,996	$ 448,644	$ 439,221	$ 397,198	$ 333,529	$ 264,594	$ 245,631	$ 170,467
Program Incentive Costs	$ -	$ 3,215	$ 7,595	$ 13,007	$ 19,934	$ 28,461	$ 38,505	$ 49,882	$ 62,289	$ 75,087	$ 87,457	$ 98,369	$ 106,629	$ 111,249	$ 112,161	$ 109,805	$ 99,299	$ 83,382	$ 66,148	$ 61,408	$ 42,617
Program Administrative Costs	$ -	$ 1,929	$ 4,557	$ 7,804	$ 11,960	$ 17,077	$ 23,103	$ 29,929	$ 37,374	$ 45,052	$ 52,474	$ 59,021	$ 63,978	$ 66,749	$ 67,297	$ 65,883	$ 59,580	$ 50,029	$ 39,689	$ 36,845	$ 25,570
Incentive + Administrative Costs	**$ -**	**$ 5,143**	**$ 12,152**	**$ 20,811**	**$ 31,895**	**$ 45,538**	**$ 61,609**	**$ 79,811**	**$ 99,663**	**$ 120,139**	**$ 139,931**	**$ 157,390**	**$ 170,607**	**$ 177,998**	**$ 179,457**	**$ 175,688**	**$ 158,879**	**$ 133,412**	**$ 105,837**	**$ 98,252**	**$ 68,187**
Incremental - Incentive Costs	**$ -**	**$ 9,644**	**$ 22,786**	**$ 39,021**	**$ 59,802**	**$ 85,384**	**$ 115,516**	**$ 149,645**	**$ 186,868**	**$ 225,260**	**$ 262,371**	**$ 295,107**	**$ 319,888**	**$ 333,747**	**$ 336,483**	**$ 329,416**	**$ 297,898**	**$ 250,147**	**$ 198,445**	**$ 184,223**	**$ 127,850**
Incremental + Administrative Costs	**$ -**	**$ 14,787**	**$ 34,938**	**$ 59,832**	**$ 91,697**	**$ 130,922**	**$ 177,125**	**$ 229,456**	**$ 286,531**	**$ 345,399**	**$ 402,302**	**$ 452,498**	**$ 490,495**	**$ 511,745**	**$ 515,940**	**$ 505,104**	**$ 456,777**	**$ 383,558**	**$ 304,283**	**$ 282,475**	**$ 196,037**

Moderately Aggressive

Total Programs Cost of Electric Savings ($1,000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 43,409	$ 115,078	$ 218,502	$ 363,381	$ 544,474	$ 738,161	$ 902,068	$ 981,762	$ 936,055	$ 855,079	$ 655,197	$ 407,393	$ 485,909	$ 269,407	$ 212,549	$ 185,871	$ 152,534	$ 104,496	$ 61,501	$ 27,429
Program Incentive Costs	$ -	$ 21,704	$ 57,539	$ 109,251	$ 181,691	$ 272,237	$ 369,080	$ 451,034	$ 490,881	$ 468,028	$ 427,540	$ 327,599	$ 203,696	$ 242,955	$ 134,703	$ 106,274	$ 92,935	$ 76,267	$ 52,248	$ 30,751	$ 13,714
Program Administrative Costs	$ -	$ 16,278	$ 43,154	$ 81,938	$ 136,268	$ 204,178	$ 276,810	$ 338,276	$ 368,161	$ 351,021	$ 320,655	$ 245,699	$ 152,772	$ 182,216	$ 101,027	$ 79,706	$ 69,702	$ 57,200	$ 39,186	$ 23,063	$ 10,286
Incentive + Administrative Costs	**$ -**	**$ 37,983**	**$ 100,693**	**$ 191,189**	**$ 317,959**	**$ 476,415**	**$ 645,891**	**$ 789,310**	**$ 859,042**	**$ 819,048**	**$ 748,194**	**$ 573,298**	**$ 356,469**	**$ 425,171**	**$ 235,731**	**$ 185,980**	**$ 162,637**	**$ 133,468**	**$ 91,434**	**$ 53,813**	**$ 24,000**
Incremental - Incentive Costs	**$ -**	**$ 21,704**	**$ 57,539**	**$ 109,251**	**$ 181,691**	**$ 272,237**	**$ 369,080**	**$ 451,034**	**$ 490,881**	**$ 468,028**	**$ 427,540**	**$ 327,599**	**$ 203,696**	**$ 242,955**	**$ 134,703**	**$ 106,274**	**$ 92,935**	**$ 76,267**	**$ 52,248**	**$ 30,751**	**$ 13,714**
Incremental + Administrative Costs	**$ -**	**$ 59,687**	**$ 158,233**	**$ 300,440**	**$ 499,650**	**$ 748,652**	**$ 1,014,971**	**$ 1,240,344**	**$ 1,349,923**	**$ 1,287,076**	**$ 1,175,734**	**$ 900,896**	**$ 560,165**	**$ 668,125**	**$ 370,434**	**$ 292,255**	**$ 255,572**	**$ 209,735**	**$ 143,683**	**$ 84,564**	**$ 37,714**

Very Aggressive

Total Programs Cost of Electric Savings ($1,000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 81,606	$ 242,772	$ 502,820	$ 861,095	$ 1,215,104	$ 1,373,170	$ 1,301,116	$ 966,065	$ 840,900	$ 481,265	$ 287,614	$ 238,411	$ 154,773	$ 76,936	$ 37,029	$ 9,809	$ 3,342	$ 695	$ 276	$ -
Program Incentive Costs	$ -	$ 81,606	$ 242,772	$ 502,820	$ 861,095	$ 1,215,104	$ 1,373,170	$ 1,301,116	$ 966,065	$ 840,900	$ 481,265	$ 287,614	$ 238,411	$ 154,773	$ 76,936	$ 37,029	$ 9,809	$ 3,342	$ 695	$ 276	$ -
Program Administrative Costs	$ -	$ 48,964	$ 145,663	$ 301,692	$ 516,657	$ 729,062	$ 823,902	$ 780,670	$ 579,639	$ 504,540	$ 288,759	$ 172,568	$ 143,047	$ 92,864	$ 46,161	$ 22,217	$ 5,885	$ 2,005	$ 417	$ 166	$ -
Incentive + Administrative Costs	**$ -**	**$ 130,569**	**$ 388,436**	**$ 804,512**	**$ 1,377,752**	**$ 1,944,166**	**$ 2,197,071**	**$ 2,081,785**	**$ 1,545,705**	**$ 1,345,440**	**$ 770,025**	**$ 460,182**	**$ 381,458**	**$ 247,637**	**$ 123,097**	**$ 59,246**	**$ 15,694**	**$ 5,347**	**$ 1,112**	**$ 442**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 130,569**	**$ 388,436**	**$ 804,512**	**$ 1,377,752**	**$ 1,944,166**	**$ 2,197,071**	**$ 2,081,785**	**$ 1,545,705**	**$ 1,345,440**	**$ 770,025**	**$ 460,182**	**$ 381,458**	**$ 247,637**	**$ 123,097**	**$ 59,246**	**$ 15,694**	**$ 5,347**	**$ 1,112**	**$ 442**	**$ -**

Very Aggressive Plus Standards

Total Programs Cost of Electric Savings ($1,000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 81,606	$ 242,772	$ 5,588,567	$ 1,339,874	$ 399,331	$ 449,342	$ 393,234	$ 262,626	$ 150,558	$ 74,290	$ 30,789	$ 11,955	$ 5,773	$ 4,849	$ 4,946	$ 3,882	$ 2,745	$ 437	$ 184	$ -
Program Incentive Costs	$ -	$ 81,606	$ 242,772	$ 5,588,567	$ 1,339,874	$ 399,331	$ 449,342	$ 393,234	$ 262,626	$ 150,558	$ 74,290	$ 30,789	$ 11,955	$ 5,773	$ 4,849	$ 4,946	$ 3,882	$ 2,745	$ 437	$ 184	$ -
Program Administrative Costs	$ -	$ 48,964	$ 145,663	$ 3,353,140	$ 803,924	$ 239,599	$ 269,605	$ 235,940	$ 157,575	$ 90,335	$ 44,574	$ 18,473	$ 7,173	$ 3,464	$ 2,909	$ 2,967	$ 2,329	$ 1,647	$ 262	$ 110	$ -
Incentive + Administrative Costs	**$ -**	**$ 130,569**	**$ 388,436**	**$ 8,941,707**	**$ 2,143,798**	**$ 638,930**	**$ 718,946**	**$ 629,174**	**$ 420,201**	**$ 240,893**	**$ 118,864**	**$ 49,263**	**$ 19,128**	**$ 9,237**	**$ 7,758**	**$ 7,913**	**$ 6,212**	**$ 4,392**	**$ 700**	**$ 294**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 130,569**	**$ 388,436**	**$ 8,941,707**	**$ 2,143,798**	**$ 638,930**	**$ 718,946**	**$ 629,174**	**$ 420,201**	**$ 240,893**	**$ 118,864**	**$ 49,263**	**$ 19,128**	**$ 9,237**	**$ 7,758**	**$ 7,913**	**$ 6,212**	**$ 4,392**	**$ 700**	**$ 294**	**$ -**

RESIDENTIAL PROGRAMS -- COSTS OF ELECTRICITY SAVINGS ($1,000'S)

Minimally Aggressive

Residential Programs Cost of Electric Savings ($1,000s)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Incremental Costs	$ -	$ 1,997	$ 4,638	$ 8,040	$ 12,302	$ 17,476	$ 23,537	$ 30,301	$ 37,734	$ 45,143	$ 51,881	$ 57,201	$ 60,378	$ 61,156	$ 59,440	$ 60,775	$ 55,805	$ 49,352	$ 41,822	$ 36,431	$ 28,645
Program Incentive Costs	$ -	$ 499	$ 1,160	$ 2,010	$ 3,076	$ 4,369	$ 5,884	$ 7,575	$ 9,433	$ 11,286	$ 12,970	$ 14,300	$ 15,095	$ 15,289	$ 14,860	$ 15,194	$ 13,951	$ 12,338	$ 10,455	$ 9,108	$ 7,161
Program Administrative Costs	$ -	$ 299	$ 696	$ 1,206	$ 1,845	$ 2,621	$ 3,531	$ 4,545	$ 5,660	$ 6,771	$ 7,782	$ 8,580	$ 9,057	$ 9,173	$ 8,916	$ 9,116	$ 8,371	$ 7,403	$ 6,273	$ 5,465	$ 4,297
Incentive + Administrative Costs	**$ -**	**$ 799**	**$ 1,855**	**$ 3,216**	**$ 4,921**	**$ 6,990**	**$ 9,415**	**$ 12,121**	**$ 15,094**	**$ 18,057**	**$ 20,752**	**$ 22,880**	**$ 24,151**	**$ 24,462**	**$ 23,776**	**$ 24,310**	**$ 22,322**	**$ 19,741**	**$ 16,729**	**$ 14,572**	**$ 11,458**
Incremental - Incentive Costs	**$ -**	**$ 1,497**	**$ 3,479**	**$ 6,030**	**$ 9,227**	**$ 13,107**	**$ 17,653**	**$ 22,726**	**$ 28,300**	**$ 33,857**	**$ 38,911**	**$ 42,901**	**$ 45,284**	**$ 45,867**	**$ 44,580**	**$ 45,581**	**$ 41,854**	**$ 37,014**	**$ 31,366**	**$ 27,323**	**$ 21,483**
Incremental + Administrative Costs	**$ -**	**$ 2,296**	**$ 5,334**	**$ 9,247**	**$ 14,147**	**$ 20,098**	**$ 27,067**	**$ 34,846**	**$ 43,394**	**$ 51,914**	**$ 59,663**	**$ 65,781**	**$ 69,435**	**$ 70,329**	**$ 68,356**	**$ 69,891**	**$ 64,176**	**$ 56,754**	**$ 48,095**	**$ 41,896**	**$ 32,941**

Moderately Aggressive

Residential Programs Cost of Electric Savings ($1,000s)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Incremental Costs	$ -	$ 6,733	$ 17,621	$ 34,201	$ 57,712	$ 87,561	$ 119,859	$ 147,246	$ 161,241	$ 156,277	$ 132,317	$ 98,857	$ 59,240	$ 49,182	$ 21,636	$ 10,208	$ 11,712	$ 8,111	$ 2,063	$ -	$ -
Program Incentive Costs	$ -	$ 3,367	$ 8,811	$ 17,100	$ 28,856	$ 43,781	$ 59,930	$ 73,623	$ 80,621	$ 78,138	$ 66,158	$ 49,429	$ 29,620	$ 24,591	$ 10,818	$ 5,104	$ 5,856	$ 4,055	$ 1,032	$ -	$ -
Program Administrative Costs	$ -	$ 2,525	$ 6,608	$ 12,825	$ 21,642	$ 32,835	$ 44,947	$ 55,217	$ 60,466	$ 58,604	$ 49,619	$ 37,072	$ 22,215	$ 18,443	$ 8,113	$ 3,828	$ 4,392	$ 3,041	$ 774	$ -	$ -
Incentive + Administrative Costs	**$ -**	**$ 5,892**	**$ 15,418**	**$ 29,926**	**$ 50,498**	**$ 76,616**	**$ 104,877**	**$ 128,840**	**$ 141,086**	**$ 136,742**	**$ 115,777**	**$ 86,500**	**$ 51,835**	**$ 43,035**	**$ 18,931**	**$ 8,932**	**$ 10,248**	**$ 7,097**	**$ 1,805**	**$ -**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ 3,367**	**$ 8,811**	**$ 17,100**	**$ 28,856**	**$ 43,781**	**$ 59,930**	**$ 73,623**	**$ 80,621**	**$ 78,138**	**$ 66,158**	**$ 49,429**	**$ 29,620**	**$ 24,591**	**$ 10,818**	**$ 5,104**	**$ 5,856**	**$ 4,055**	**$ 1,032**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 9,258**	**$ 24,229**	**$ 47,026**	**$ 79,354**	**$ 120,397**	**$ 164,806**	**$ 202,463**	**$ 221,707**	**$ 214,880**	**$ 181,936**	**$ 135,929**	**$ 81,455**	**$ 67,626**	**$ 29,749**	**$ 14,036**	**$ 16,104**	**$ 11,152**	**$ 2,837**	**$ -**	**$ -**

Very Aggressive

Residential Programs Cost of Electric Savings ($1,000s)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Incremental Costs	$ -	$ 12,658	$ 37,488	$ 80,798	$ 142,679	$ 206,367	$ 241,030	$ 224,119	$ 164,604	$ 121,980	$ 62,706	$ 24,183	$ 19,139	$ 9,160	$ 2,100	$ 1,871	$ 1,651	$ 1,440	$ -	$ -	$ -
Program Incentive Costs	$ -	$ 12,658	$ 37,488	$ 80,798	$ 142,679	$ 206,367	$ 241,030	$ 224,119	$ 164,604	$ 121,980	$ 62,706	$ 24,183	$ 19,139	$ 9,160	$ 2,100	$ 1,871	$ 1,651	$ 1,440	$ -	$ -	$ -
Program Administrative Costs	$ -	$ 7,595	$ 22,493	$ 48,479	$ 85,607	$ 123,820	$ 144,618	$ 134,471	$ 98,763	$ 73,188	$ 37,623	$ 14,510	$ 11,483	$ 5,496	$ 1,260	$ 1,123	$ 991	$ 864	$ -	$ -	$ -
Incentive + Administrative Costs	**$ -**	**$ 20,253**	**$ 59,982**	**$ 129,277**	**$ 228,286**	**$ 330,187**	**$ 385,649**	**$ 358,591**	**$ 263,367**	**$ 195,168**	**$ 100,329**	**$ 38,693**	**$ 30,622**	**$ 14,656**	**$ 3,360**	**$ 2,994**	**$ 2,642**	**$ 2,304**	**$ -**	**$ -**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 20,253**	**$ 59,982**	**$ 129,277**	**$ 228,286**	**$ 330,187**	**$ 385,649**	**$ 358,591**	**$ 263,367**	**$ 195,168**	**$ 100,329**	**$ 38,693**	**$ 30,622**	**$ 14,656**	**$ 3,360**	**$ 2,994**	**$ 2,642**	**$ 2,304**	**$ -**	**$ -**	**$ -**

Very Aggressive Plus Standards

Residential Programs Cost of Electric Savings ($1,000s)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Incremental Costs	$ -	$ 12,658	$ 37,488	$ 580,664	$ 262,229	$ 121,926	$ 154,314	$ 154,493	$ 111,057	$ 66,510	$ 28,789	$ 8,841	$ 2,345	$ 2,337	$ 2,100	$ 1,871	$ 1,651	$ 1,440	$ -	$ -	$ -
Program Incentive Costs	$ -	$ 12,658	$ 37,488	$ 580,664	$ 262,229	$ 121,926	$ 154,314	$ 154,493	$ 111,057	$ 66,510	$ 28,789	$ 8,841	$ 2,345	$ 2,337	$ 2,100	$ 1,871	$ 1,651	$ 1,440	$ -	$ -	$ -
Program Administrative Costs	$ -	$ 7,595	$ 22,493	$ 348,398	$ 157,337	$ 73,156	$ 92,588	$ 92,696	$ 66,634	$ 39,906	$ 17,273	$ 5,305	$ 1,407	$ 1,402	$ 1,260	$ 1,123	$ 991	$ 864	$ -	$ -	$ -
Incentive + Administrative Costs	**$ -**	**$ 20,253**	**$ 59,982**	**$ 929,062**	**$ 419,566**	**$ 195,082**	**$ 246,903**	**$ 247,189**	**$ 177,691**	**$ 106,415**	**$ 46,062**	**$ 14,146**	**$ 3,753**	**$ 3,739**	**$ 3,360**	**$ 2,994**	**$ 2,642**	**$ 2,304**	**$ -**	**$ -**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 20,253**	**$ 59,982**	**$ 929,062**	**$ 419,566**	**$ 195,082**	**$ 246,903**	**$ 247,189**	**$ 177,691**	**$ 106,415**	**$ 46,062**	**$ 14,146**	**$ 3,753**	**$ 3,739**	**$ 3,360**	**$ 2,994**	**$ 2,642**	**$ 2,304**	**$ -**	**$ -**	**$ -**

COMMERCIAL PROGRAMS COSTS OF ELECTRICITY SAVINGS ($1,000'S)

Minimally Aggressive

Commercial Programs Cost of Electric Savings ($1,000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 7,646	$ 18,264	$ 31,264	$ 48,259	$ 69,554	$ 94,986	$ 124,223	$ 156,429	$ 190,176	$ 223,404	$ 253,441	$ 277,094	$ 291,305	$ 294,615	$ 285,908	$ 257,822	$ 215,198	$ 169,405	$ 177,011	$ 123,803
Program Incentive Costs	$ -	$ 1,911	$ 4,566	$ 7,816	$ 12,065	$ 17,388	$ 23,746	$ 31,056	$ 39,107	$ 47,544	$ 55,851	$ 63,360	$ 69,274	$ 72,826	$ 73,654	$ 71,477	$ 64,456	$ 53,799	$ 42,351	$ 44,253	$ 30,951
Program Administrative Costs	$ -	$ 1,147	$ 2,740	$ 4,690	$ 7,239	$ 10,433	$ 14,248	$ 18,633	$ 23,464	$ 28,526	$ 33,511	$ 38,016	$ 41,564	$ 43,696	$ 44,192	$ 42,886	$ 38,673	$ 32,280	$ 25,411	$ 26,552	$ 18,570
Incentive + Administrative Costs	**$ -**	**$ 3,058**	**$ 7,305**	**$ 12,505**	**$ 19,304**	**$ 27,822**	**$ 37,994**	**$ 49,689**	**$ 62,572**	**$ 76,070**	**$ 89,362**	**$ 101,377**	**$ 110,838**	**$ 116,522**	**$ 117,846**	**$ 114,363**	**$ 103,129**	**$ 86,079**	**$ 67,762**	**$ 70,805**	**$ 49,521**
Incremental - Incentive Costs	**$ -**	**$ 5,734**	**$ 13,698**	**$ 23,448**	**$ 36,195**	**$ 52,165**	**$ 71,239**	**$ 93,167**	**$ 117,322**	**$ 142,632**	**$ 167,553**	**$ 190,081**	**$ 207,821**	**$ 218,479**	**$ 220,961**	**$ 214,431**	**$ 193,367**	**$ 161,398**	**$ 127,054**	**$ 132,758**	**$ 92,852**
Incremental + Administrative Costs	**$ -**	**$ 8,793**	**$ 21,003**	**$ 35,953**	**$ 55,498**	**$ 79,987**	**$ 109,234**	**$ 142,857**	**$ 179,893**	**$ 218,702**	**$ 256,915**	**$ 291,457**	**$ 318,658**	**$ 335,001**	**$ 338,808**	**$ 328,794**	**$ 296,495**	**$ 247,478**	**$ 194,816**	**$ 203,563**	**$ 142,374**

Moderately Aggressive

Commercial Programs Cost of Electric Savings ($1,000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 25,830	$ 69,281	$ 131,560	$ 220,311	$ 332,834	$ 454,406	$ 558,210	$ 609,225	$ 581,374	$ 556,750	$ 431,267	$ 273,440	$ 340,188	$ 176,616	$ 123,641	$ 103,929	$ 83,254	$ 57,925	$ 33,555	$ 14,616
Program Incentive Costs	$ -	$ 12,915	$ 34,641	$ 65,780	$ 110,156	$ 166,417	$ 227,203	$ 279,105	$ 304,612	$ 290,687	$ 278,375	$ 215,634	$ 136,720	$ 170,094	$ 88,308	$ 61,820	$ 51,965	$ 41,627	$ 28,962	$ 16,778	$ 7,308
Program Administrative Costs	$ -	$ 9,686	$ 25,981	$ 49,335	$ 82,617	$ 124,813	$ 170,402	$ 209,329	$ 228,459	$ 218,015	$ 208,781	$ 161,725	$ 102,540	$ 127,570	$ 66,231	$ 46,365	$ 38,974	$ 31,220	$ 21,722	$ 12,583	$ 5,481
Incentive + Administrative Costs	**$ -**	**$ 22,601**	**$ 60,621**	**$ 115,115**	**$ 192,772**	**$ 291,230**	**$ 397,606**	**$ 488,434**	**$ 533,072**	**$ 508,703**	**$ 487,157**	**$ 377,359**	**$ 239,260**	**$ 297,664**	**$ 154,539**	**$ 108,185**	**$ 90,938**	**$ 72,847**	**$ 50,684**	**$ 29,361**	**$ 12,789**
Incremental - Incentive Costs	**$ -**	**$ 12,915**	**$ 34,641**	**$ 65,780**	**$ 110,156**	**$ 166,417**	**$ 227,203**	**$ 279,105**	**$ 304,612**	**$ 290,687**	**$ 278,375**	**$ 215,634**	**$ 136,720**	**$ 170,094**	**$ 88,308**	**$ 61,820**	**$ 51,965**	**$ 41,627**	**$ 28,962**	**$ 16,778**	**$ 7,308**
Incremental + Administrative Costs	**$ -**	**$ 35,516**	**$ 95,262**	**$ 180,896**	**$ 302,928**	**$ 457,646**	**$ 624,809**	**$ 767,539**	**$ 837,684**	**$ 799,390**	**$ 765,532**	**$ 592,992**	**$ 375,980**	**$ 467,758**	**$ 242,848**	**$ 170,006**	**$ 142,903**	**$ 114,474**	**$ 79,646**	**$ 46,139**	**$ 20,097**

Very Aggressive

Commercial Programs Cost of Electric Savings ($1,000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 48,591	$ 146,284	$ 302,709	$ 520,806	$ 737,123	$ 830,540	$ 815,185	$ 613,637	$ 551,934	$ 295,112	$ 165,756	$ 126,200	$ 81,139	$ 41,476	$ 20,308	$ 4,903	$ 1,902	$ 695	$ 276	$ -
Program Incentive Costs	$ -	$ 48,591	$ 146,284	$ 302,709	$ 520,806	$ 737,123	$ 830,540	$ 815,185	$ 613,637	$ 551,934	$ 295,112	$ 165,756	$ 126,200	$ 81,139	$ 41,476	$ 20,308	$ 4,903	$ 1,902	$ 695	$ 276	$ -
Program Administrative Costs	$ -	$ 29,155	$ 87,771	$ 181,626	$ 312,484	$ 442,274	$ 498,324	$ 489,111	$ 368,182	$ 331,160	$ 177,067	$ 99,453	$ 75,720	$ 48,684	$ 24,886	$ 12,185	$ 2,942	$ 1,141	$ 417	$ 166	$ -
Incentive + Administrative Costs	**$ -**	**$ 77,746**	**$ 234,055**	**$ 484,335**	**$ 833,290**	**$ 1,179,396**	**$ 1,328,865**	**$ 1,304,296**	**$ 981,819**	**$ 883,095**	**$ 472,179**	**$ 265,209**	**$ 201,919**	**$ 129,823**	**$ 66,362**	**$ 32,493**	**$ 7,845**	**$ 3,043**	**$ 1,112**	**$ 442**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 77,746**	**$ 234,055**	**$ 484,335**	**$ 833,290**	**$ 1,179,396**	**$ 1,328,865**	**$ 1,304,296**	**$ 981,819**	**$ 883,095**	**$ 472,179**	**$ 265,209**	**$ 201,919**	**$ 129,823**	**$ 66,362**	**$ 32,493**	**$ 7,845**	**$ 3,043**	**$ 1,112**	**$ 442**	**$ -**

Very Aggressive Plus Standards

Commercial Programs Cost of Electric Savings ($1,000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 48,591	$ 146,284	$ 3,523,066	$ 899,112	$ 176,186	$ 187,849	$ 157,529	$ 107,901	$ 66,004	$ 38,589	$ 20,999	$ 9,507	$ 3,436	$ 2,749	$ 3,074	$ 2,231	$ 1,305	$ 437	$ 184	$ -
Program Incentive Costs	$ -	$ 48,591	$ 146,284	$ 3,523,066	$ 899,112	$ 176,186	$ 187,849	$ 157,529	$ 107,901	$ 66,004	$ 38,589	$ 20,999	$ 9,507	$ 3,436	$ 2,749	$ 3,074	$ 2,231	$ 1,305	$ 437	$ 184	$ -
Program Administrative Costs	$ -	$ 29,155	$ 87,771	$ 2,113,839	$ 539,467	$ 105,712	$ 112,709	$ 94,518	$ 64,741	$ 39,603	$ 23,153	$ 12,599	$ 5,704	$ 2,062	$ 1,649	$ 1,845	$ 1,339	$ 783	$ 262	$ 110	$ -
Incentive + Administrative Costs	**$ -**	**$ 77,746**	**$ 234,055**	**$ 5,636,905**	**$ 1,438,579**	**$ 281,898**	**$ 300,559**	**$ 252,047**	**$ 172,641**	**$ 105,607**	**$ 61,743**	**$ 33,598**	**$ 15,212**	**$ 5,498**	**$ 4,398**	**$ 4,919**	**$ 3,570**	**$ 2,088**	**$ 700**	**$ 294**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 77,746**	**$ 234,055**	**$ 5,636,905**	**$ 1,438,579**	**$ 281,898**	**$ 300,559**	**$ 252,047**	**$ 172,641**	**$ 105,607**	**$ 61,743**	**$ 33,598**	**$ 15,212**	**$ 5,498**	**$ 4,398**	**$ 4,919**	**$ 3,570**	**$ 2,088**	**$ 700**	**$ 294**	**$ -**

INDUSTRIAL PROGRAMS COST OF ELECTRICITY SAVINGS (1,000'S)

Minimally Aggressive

Industrial Programs Cost of Electric Savings ($1,000s)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 3,216	$ 7,479	$ 12,723	$ 19,175	$ 26,815	$ 35,499	$ 45,003	$ 54,994	$ 65,029	$ 74,542	$ 82,834	$ 89,045	$ 92,535	$ 94,588	$ 92,538	$ 83,571	$ 68,980	$ 53,366	$ 32,188	$ 18,020
Program Incentive Costs	$ -	$ 804	$ 1,870	$ 3,181	$ 4,794	$ 6,704	$ 8,875	$ 11,251	$ 13,749	$ 16,257	$ 18,636	$ 20,708	$ 22,261	$ 23,134	$ 23,647	$ 23,135	$ 20,893	$ 17,245	$ 13,342	$ 8,047	$ 4,505
Program Administrative Costs	$ -	$ 482	$ 1,122	$ 1,909	$ 2,876	$ 4,022	$ 5,325	$ 6,750	$ 8,249	$ 9,754	$ 11,181	$ 12,425	$ 13,357	$ 13,880	$ 14,188	$ 13,881	$ 12,536	$ 10,347	$ 8,005	$ 4,828	$ 2,703
Incentive + Administrative Costs	**$ -**	**$ 1,287**	**$ 2,992**	**$ 5,089**	**$ 7,670**	**$ 10,726**	**$ 14,200**	**$ 18,001**	**$ 21,998**	**$ 26,012**	**$ 29,817**	**$ 33,133**	**$ 35,618**	**$ 37,014**	**$ 37,835**	**$ 37,015**	**$ 33,428**	**$ 27,592**	**$ 21,347**	**$ 12,875**	**$ 7,208**
Incremental - Incentive Costs	**$ -**	**$ 2,412**	**$ 5,609**	**$ 9,543**	**$ 14,381**	**$ 20,112**	**$ 26,624**	**$ 33,752**	**$ 41,246**	**$ 48,772**	**$ 55,907**	**$ 62,125**	**$ 66,784**	**$ 69,401**	**$ 70,941**	**$ 69,404**	**$ 62,678**	**$ 51,735**	**$ 40,025**	**$ 24,141**	**$ 13,515**
Incremental + Administrative Costs	**$ -**	**$ 3,699**	**$ 8,601**	**$ 14,632**	**$ 22,051**	**$ 30,838**	**$ 40,824**	**$ 51,753**	**$ 63,243**	**$ 74,783**	**$ 85,724**	**$ 95,259**	**$ 102,402**	**$ 106,416**	**$ 108,776**	**$ 106,419**	**$ 96,106**	**$ 79,327**	**$ 61,371**	**$ 37,016**	**$ 20,722**

Moderately Aggressive

Industrial Programs Cost of Electric Savings ($1,000s)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 10,845	$ 28,176	$ 52,741	$ 85,358	$ 124,079	$ 163,895	$ 196,613	$ 211,296	$ 198,404	$ 166,012	$ 125,073	$ 74,713	$ 96,539	$ 71,155	$ 78,701	$ 70,229	$ 61,170	$ 44,509	$ 27,946	$ 12,813
Program Incentive Costs	$ -	$ 5,423	$ 14,088	$ 26,370	$ 42,679	$ 62,040	$ 81,948	$ 98,306	$ 105,648	$ 99,202	$ 83,006	$ 62,536	$ 37,356	$ 48,270	$ 35,577	$ 39,350	$ 35,115	$ 30,585	$ 22,254	$ 13,973	$ 6,406
Program Administrative Costs	$ -	$ 4,067	$ 10,566	$ 19,778	$ 32,009	$ 46,530	$ 61,461	$ 73,730	$ 79,236	$ 74,402	$ 62,254	$ 46,902	$ 28,017	$ 36,202	$ 26,683	$ 29,513	$ 26,336	$ 22,939	$ 16,691	$ 10,480	$ 4,805
Incentive + Administrative Costs	**$ -**	**$ 9,490**	**$ 24,654**	**$ 46,148**	**$ 74,688**	**$ 108,569**	**$ 143,408**	**$ 172,036**	**$ 184,884**	**$ 173,604**	**$ 145,260**	**$ 109,439**	**$ 65,374**	**$ 84,472**	**$ 62,260**	**$ 68,863**	**$ 61,451**	**$ 53,524**	**$ 38,945**	**$ 24,452**	**$ 11,211**
Incremental - Incentive Costs	**$ -**	**$ 5,423**	**$ 14,088**	**$ 26,370**	**$ 42,679**	**$ 62,040**	**$ 81,948**	**$ 98,306**	**$ 105,648**	**$ 99,202**	**$ 83,006**	**$ 62,536**	**$ 37,356**	**$ 48,270**	**$ 35,577**	**$ 39,350**	**$ 35,115**	**$ 30,585**	**$ 22,254**	**$ 13,973**	**$ 6,406**
Incremental + Administrative Costs	**$ -**	**$ 14,912**	**$ 38,742**	**$ 72,518**	**$ 117,367**	**$ 170,609**	**$ 225,356**	**$ 270,342**	**$ 290,532**	**$ 272,806**	**$ 228,266**	**$ 171,975**	**$ 102,730**	**$ 132,741**	**$ 97,838**	**$ 108,214**	**$ 96,565**	**$ 84,109**	**$ 61,200**	**$ 38,425**	**$ 17,618**

Very Aggressive

Industrial Programs Cost of Electric Savings ($1,000s)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 20,357	$ 58,999	$ 119,313	$ 197,610	$ 271,614	$ 301,599	$ 261,812	$ 187,824	$ 166,986	$ 123,448	$ 97,675	$ 93,073	$ 64,474	$ 33,359	$ 14,850	$ 3,254	$ -	$ -	$ -	$ -
Program Incentive Costs	$ -	$ 20,357	$ 58,999	$ 119,313	$ 197,610	$ 271,614	$ 301,599	$ 261,812	$ 187,824	$ 166,986	$ 123,448	$ 97,675	$ 93,073	$ 64,474	$ 33,359	$ 14,850	$ 3,254	$ -	$ -	$ -	$ -
Program Administrative Costs	$ -	$ 12,214	$ 35,400	$ 71,588	$ 118,566	$ 162,968	$ 180,959	$ 157,087	$ 112,695	$ 100,191	$ 74,069	$ 58,605	$ 55,844	$ 38,684	$ 20,015	$ 8,910	$ 1,952	$ -	$ -	$ -	$ -
Incentive + Administrative Costs	**$ -**	**$ 32,571**	**$ 94,399**	**$ 190,901**	**$ 316,176**	**$ 434,583**	**$ 482,558**	**$ 418,898**	**$ 300,519**	**$ 267,177**	**$ 197,516**	**$ 156,280**	**$ 148,917**	**$ 103,159**	**$ 53,375**	**$ 23,759**	**$ 5,207**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 32,571**	**$ 94,399**	**$ 190,901**	**$ 316,176**	**$ 434,583**	**$ 482,558**	**$ 418,898**	**$ 300,519**	**$ 267,177**	**$ 197,516**	**$ 156,280**	**$ 148,917**	**$ 103,159**	**$ 53,375**	**$ 23,759**	**$ 5,207**	**$ -**	**$ -**	**$ -**	**$ -**

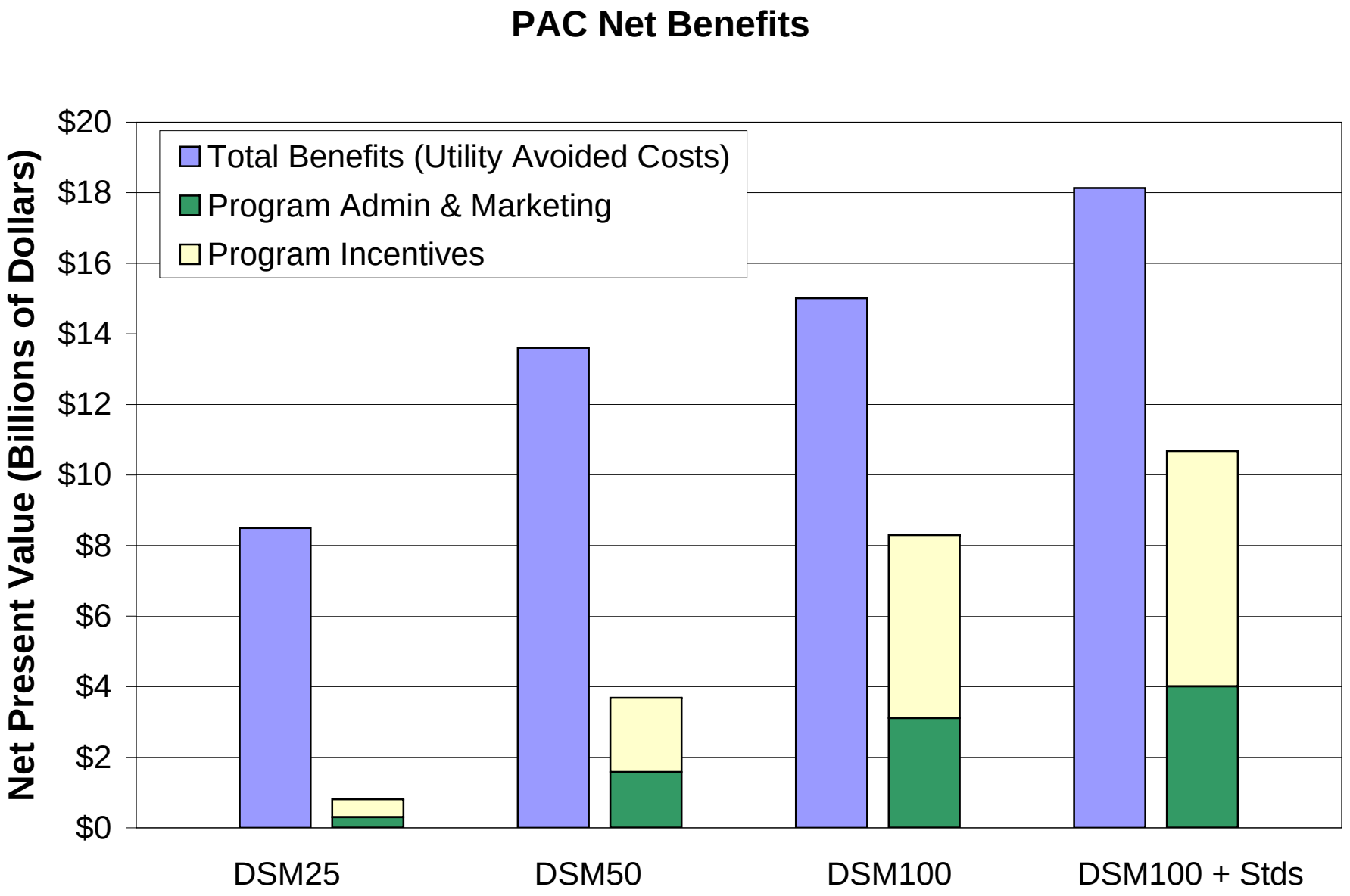
Very Aggressive Plus Standards

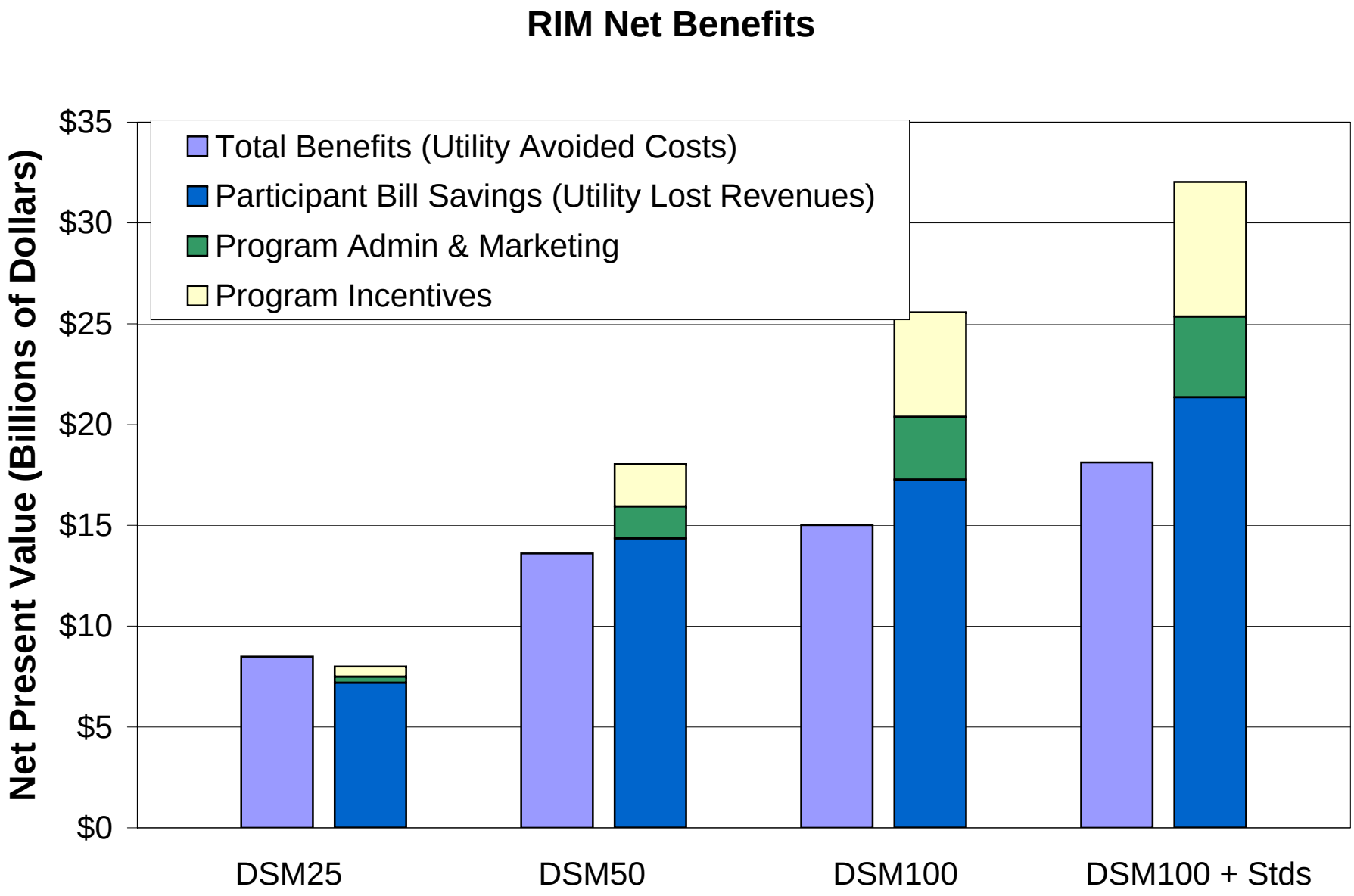
Industrial Programs Cost of Electric Savings ($1,000s)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	$ -	$ 20,357	$ 58,999	$ 1,484,838	$ 178,533	$ 101,219	$ 107,178	$ 81,211	$ 43,668	$ 18,044	$ 6,912	$ 949	$ 102	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Incentive Costs	$ -	$ 20,357	$ 58,999	$ 1,484,838	$ 178,533	$ 101,219	$ 107,178	$ 81,211	$ 43,668	$ 18,044	$ 6,912	$ 949	$ 102	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Program Administrative Costs	$ -	$ 12,214	$ 35,400	$ 890,903	$ 107,120	$ 60,731	$ 64,307	$ 48,727	$ 26,201	$ 10,827	$ 4,147	$ 570	$ 61	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incentive + Administrative Costs	**$ -**	**$ 32,571**	**$ 94,399**	**$ 2,375,740**	**$ 285,653**	**$ 161,950**	**$ 171,485**	**$ 129,938**	**$ 69,869**	**$ 28,871**	**$ 11,059**	**$ 1,519**	**$ 163**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental - Incentive Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Incremental + Administrative Costs	**$ -**	**$ 32,571**	**$ 94,399**	**$ 2,375,740**	**$ 285,653**	**$ 161,950**	**$ 171,485**	**$ 129,938**	**$ 69,869**	**$ 28,871**	**$ 11,059**	**$ 1,519**	**$ 163**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

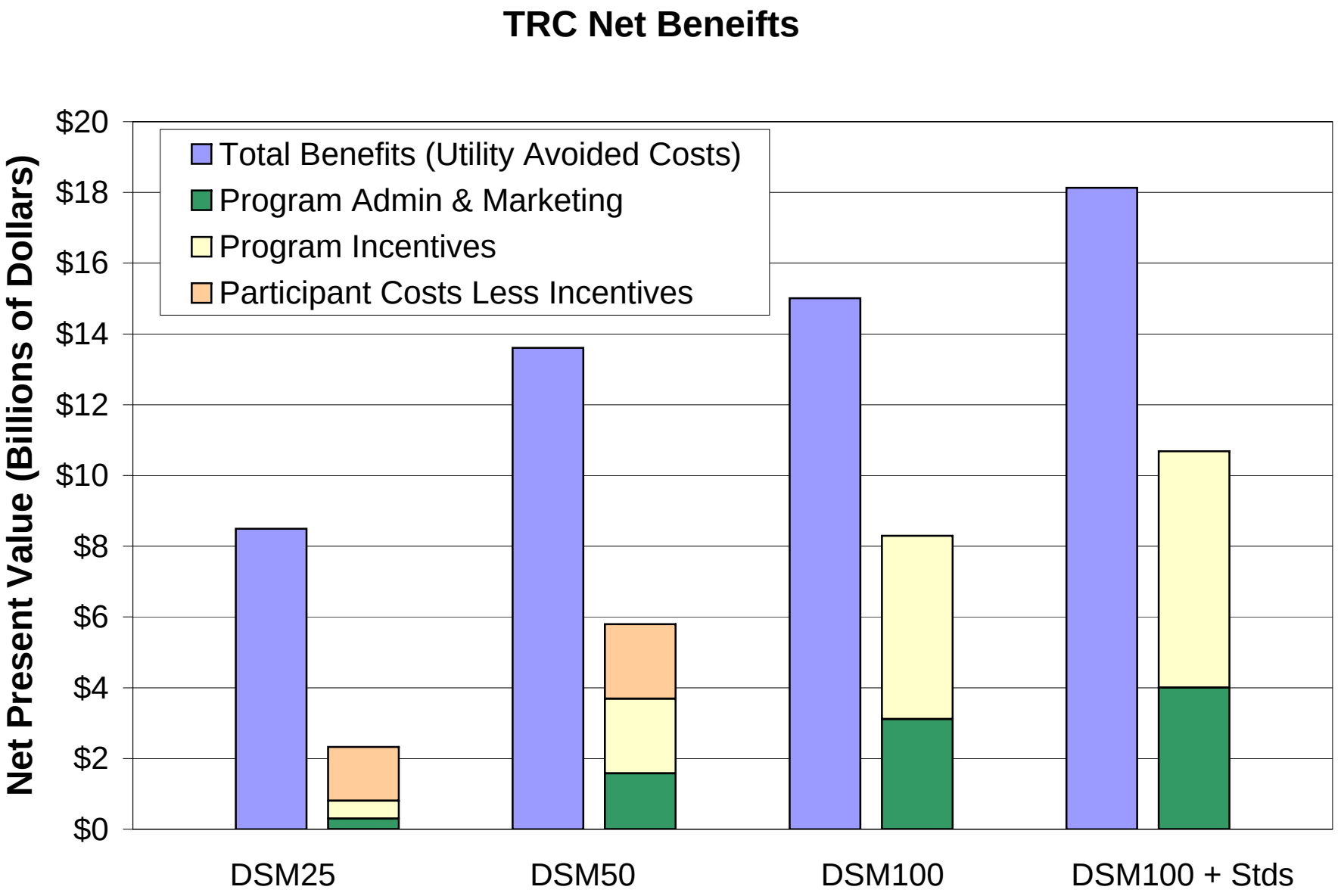
CDM PROGRAM COSTS								
DSM25	**Participant Net Benefits**	**PCT BCR**	**TRC Net Benefits**	**TRC BCR**	**PAC Net Benefits**	**PAC BCR**	**RIM Net Benefits**	**RIM BCR**
Residential Space Heat	$ 379,034	5.89	$ 262,214	3.94	$ 320,407	11.32	$ (116,820)	0.75
Residential Central A/C	$ 98,266	5.63	$ 67,927	3.78	$ 83,856	10.87	$ (30,339)	0.75
Residential Room A/C	$ 4,507	3.24	$ 2,664	2.15	$ 4,171	6.19	$ (1,843)	0.73
Residential Lighting	$ 569,663	5.17	$ 431,537	3.75	$ 533,928	10.78	$ (138,126)	0.81
Residential Refrigerator	$ 69,398	0.00	$ 160,813	0.00	$ 160,813	0.00	$ 91,415	2.32
Residential Freezer	$ 64,638	0.00	$ 106,667	0.00	$ 106,667	0.00	$ 42,030	1.65
Residential Dishwasher	$ 16,791	0.00	$ 20,904	0.00	$ 20,904	0.00	$ 4,112	1.24
Residential Hot Water	$ 221,416	8.67	$ 143,263	5.31	$ 164,918	15.28	$ (78,153)	0.69
Residential Clothes Dryer	$ 26,923	0.00	$ 65,639	0.00	$ 65,639	0.00	$ 38,716	2.44
Residential Clothes Washer	$ 11,579	3.11	$ 19,560	4.10	$ 23,680	11.78	$ 7,981	1.45
Commercial Heating	$ 88,277	7.80	$ 80,296	6.38	$ 90,030	18.34	$ (7,981)	0.92
Commercial Ventilation	$ 153,840	4.64	$ 115,446	3.37	$ 147,149	9.70	$ (38,394)	0.81
Commercial Cooling	$ 465,128	2.86	$ 387,686	2.35	$ 575,130	6.75	$ (77,442)	0.90
Commercial Interior Lighting	$ 1,134,279	2.27	$ 924,489	1.90	$ 1,595,212	5.46	$ (209,790)	0.90
Commercial Exterior Lighting	$ 333,870	5.12	$ 438,721	5.71	$ 499,474	16.42	$ 104,851	1.25
Commercial Refrigeration	$ -	0.00	$ -	0.00	$ -	0.00	$ -	0.00
Commercial Office Equipment	$ 173,412	5.55	$ 124,914	3.85	$ 153,480	11.07	$ (48,498)	0.78
Commercial Hot Water	$ -	0.00	$ -	0.00	$ -	0.00	$ -	0.00
Industrial HVAC	$ 379,157	3.44	$ 536,831	4.01	$ 653,265	11.52	$ 157,674	1.28
Industrial Process Cooling	$ 129,726	12.01	$ 173,442	13.79	$ 182,283	39.66	$ 43,716	1.31
Industrial Process Heating & Boile	$ 777,284	8.46	$ 1,517,927	13.67	$ 1,596,060	39.30	$ 740,644	1.83
Industrial Interior Lighting	$ 126,636	2.23	$ 133,756	2.13	$ 210,739	6.13	$ 7,120	1.03
Industrial Exterior Lighting	$ 50,188	4.39	$ 75,626	5.44	$ 86,729	15.65	$ 25,438	1.38
Industrial Process Machine Drive	$ 398,002	9.98	$ 378,363	8.42	$ 411,622	24.21	$ (19,639)	0.96
	$ 5,672,012	**3.80**	**$ 6,168,685**	**3.65**	**$ 7,686,153**	**10.50**	**$ 496,673**	**1.06**
Residential	**$ 1,462,214**	**6.38**	**$ 1,281,187**	**5.10**	**$ 1,484,983**	**14.66**	**$ (181,027)**	**0.90**
Commercial	**$ 2,348,805**	**2.78**	**$ 2,071,552**	**2.37**	**$ 3,060,473**	**6.80**	**$ (277,253)**	**0.93**
Industrial	**$ 1,860,993**	**5.30**	**$ 2,815,946**	**6.66**	**$ 3,140,697**	**19.13**	**$ 954,953**	**1.40**
DSM50	**Participant Net Benefits**	**PCT BCR**	**TRC Net Benefits**	**TRC BCR**	**PAC Net Benefits**	**PAC BCR**	**RIM Net Benefits**	**RIM BCR**
Residential Space Heat	$ 787,637	5.83	$ 407,813	2.82	$ 489,423	4.43	$ (379,824)	0.62
Residential Central A/C	$ 230,360	5.65	$ 124,163	2.82	$ 148,910	4.44	$ (106,197)	0.64
Residential Room A/C	$ 12,143	3.41	$ 4,353	1.63	$ 6,871	2.56	$ (7,789)	0.59
Residential Lighting	$ 1,097,689	4.97	$ 516,575	2.36	$ 654,651	3.71	$ (581,114)	0.61
Residential Refrigerator	$ 190,868	0.00	$ 320,818	0.00	$ 320,818	0.00	$ 129,950	1.68
Residential Freezer	$ 127,592	0.00	$ 145,594	0.00	$ 145,594	0.00	$ 18,003	1.14
Residential Dishwasher	$ 24,675	0.00	$ 18,487	0.00	$ 18,487	0.00	$ (6,188)	0.75
Residential Hot Water	$ 492,006	8.58	$ 289,626	4.25	$ 322,066	6.67	$ (202,381)	0.65
Residential Clothes Dryer	$ 64,102	0.00	$ 112,441	0.00	$ 112,441	0.00	$ 48,339	1.75
Residential Clothes Washer	$ 26,572	3.19	$ 18,227	2.09	$ 24,302	3.29	$ (8,346)	0.81
Commercial Heating	$ 155,377	7.50	$ 105,125	4.20	$ 117,082	6.60	$ (50,252)	0.73
Commercial Ventilation	$ 309,653	4.72	$ 176,071	2.54	$ 217,672	3.99	$ (133,582)	0.68
Commercial Cooling	$ 1,405,045	3.05	$ 653,940	1.69	$ 996,302	2.66	$ (751,105)	0.68
Commercial Interior Lighting	$ 2,207,635	2.34	$ 261,726	1.12	$ 1,083,791	1.75	$ (1,945,909)	0.56
Commercial Exterior Lighting	$ 592,117	4.98	$ 372,930	2.82	$ 447,401	4.43	$ (219,187)	0.72
Commercial Refrigeration	$ -	0.00	$ -	0.00	$ -	0.00	$ -	0.00
Commercial Office Equipment	$ 416,797	5.11	$ 249,934	2.79	$ 300,639	4.39	$ (166,862)	0.70
Commercial Hot Water	$ -	0.00	$ -	0.00	$ -	0.00	$ -	0.00
Industrial HVAC	$ 966,749	3.49	$ 1,081,856	3.02	$ 1,276,300	4.75	$ 115,107	1.08
Industrial Process Cooling	$ 236,038	11.47	$ 215,341	7.95	$ 226,616	12.49	$ (20,697)	0.92
Industrial Process Heating & Boile	$ 1,357,196	8.00	$ 1,272,197	5.77	$ 1,369,133	9.07	$ (84,999)	0.95
Industrial Interior Lighting	$ 256,541	2.31	$ 70,074	1.26	$ 167,829	1.98	$ (186,467)	0.65
Industrial Exterior Lighting	$ 91,186	4.28	$ 64,575	2.69	$ 78,496	4.22	$ (26,611)	0.79
Industrial Process Machine Drive	$ 1,199,413	10.37	$ 1,329,356	8.55	$ 1,393,344	13.44	$ 129,943	1.09
	$ 5,672,012	**3.80**	**$ 6,168,685**	**3.65**	**$ 7,686,153**	**10.50**	**$ 496,673**	**1.06**
Residential	**$ 1,462,214**	**6.38**	**$ 1,281,187**	**5.10**	**$ 1,484,983**	**14.66**	**$ (181,027)**	**0.90**
Commercial	**$ 2,348,805**	**2.78**	**$ 2,071,552**	**2.37**	**$ 3,060,473**	**6.80**	**$ (277,253)**	**0.93**
Industrial	**$ 1,860,993**	**5.30**	**$ 2,815,946**	**6.66**	**$ 3,140,697**	**19.13**	**$ 954,953**	**1.40**

CDM PROGRAM COSTS								
DSM100	**Participant Net Benefits**	**PCT BCR**	**TRC Net Benefits**	**TRC BCR**	**PAC Net Benefits**	**PAC BCR**	**RIM Net Benefits**	**RIM BCR**
Residential Space Heat	$ 1,122,291	6.22	$ 467,029	2.36	$ 467,029	2.36	$ (655,261)	0.55
Residential Central A/C	$ 329,357	6.02	$ 134,381	2.28	$ 134,381	2.28	$ (194,976)	0.55
Residential Room A/C	$ 21,499	3.87	$ 4,007	1.33	$ 4,007	1.33	$ (17,492)	0.48
Residential Lighting	$ 1,469,583	5.29	$ 513,678	1.94	$ 513,678	1.94	$ (955,906)	0.53
Residential Refrigerator	$ 256,100	0.00	$ 309,191	0.00	$ 309,191	0.00	$ 53,091	1.21
Residential Freezer	$ 159,147	0.00	$ 154,907	0.00	$ 154,907	0.00	$ (4,240)	0.97
Residential Dishwasher	$ 27,305	0.00	$ 19,852	0.00	$ 19,852	0.00	$ (7,453)	0.73
Residential Hot Water	$ 689,936	8.93	$ 358,544	3.57	$ 358,544	3.57	$ (331,392)	0.60
Residential Clothes Dryer	$ 80,142	0.00	$ 120,722	0.00	$ 120,722	0.00	$ 40,580	1.51
Residential Clothes Washer	$ 39,898	3.61	$ 12,785	1.52	$ 12,785	1.52	$ (27,112)	0.58
Commercial Heating	$ 193,143	7.76	$ 112,409	3.46	$ 112,409	3.46	$ (80,734)	0.66
Commercial Ventilation	$ 433,787	5.15	$ 188,751	2.13	$ 188,751	2.13	$ (245,037)	0.59
Commercial Cooling	$ 2,132,492	3.45	$ 370,540	1.27	$ 370,540	1.27	$ (1,761,952)	0.50
Commercial Interior Lighting	$ 3,435,541	2.77	$ (290,218)	0.91	$ (290,218)	0.91	$ (3,725,759)	0.43
Commercial Exterior Lighting	$ 757,981	5.29	$ 349,231	2.23	$ 349,231	2.23	$ (408,749)	0.61
Commercial Refrigeration	$ -	0.00	$ -	0.00	$ -	0.00	$ -	0.00
Commercial Office Equipment	$ 563,659	5.40	$ 255,674	2.25	$ 255,674	2.25	$ (307,985)	0.60
Commercial Hot Water	$ -	0.00	$ -	0.00	$ -	0.00	$ -	0.00
Industrial HVAC	$ 1,441,180	3.87	$ 719,369	1.90	$ 719,369	1.90	$ (721,810)	0.68
Industrial Process Cooling	$ 297,360	11.64	$ 239,641	6.36	$ 239,641	6.36	$ (57,719)	0.83
Industrial Process Heating & Boile	$ 1,700,262	8.21	$ 1,271,527	4.37	$ 1,271,527	4.37	$ (428,735)	0.79
Industrial Interior Lighting	$ 409,848	2.74	$ 9,445	1.03	$ 9,445	1.03	$ (400,403)	0.49
Industrial Exterior Lighting	$ 121,428	4.60	$ 60,902	2.13	$ 60,902	2.13	$ (60,526)	0.66
Industrial Process Machine Drive	$ 1,590,090	10.56	$ 1,329,879	5.99	$ 1,329,879	5.99	$ (260,211)	0.86
	$ 5,672,012	**3.80**	**$ 6,168,685**	**3.65**	**$ 7,686,153**	**10.50**	**$ 496,673**	**1.06**
Residential	**$ 1,462,214**	**6.38**	**$ 1,281,187**	**5.10**	**$ 1,484,983**	**14.66**	**$ (181,027)**	**0.90**
Commercial	**$ 2,348,805**	**2.78**	**$ 2,071,552**	**2.37**	**$ 3,060,473**	**6.80**	**$ (277,253)**	**0.93**
Industrial	**$ 1,860,993**	**5.30**	**$ 2,815,946**	**6.66**	**$ 3,140,697**	**19.13**	**$ 954,953**	**1.40**

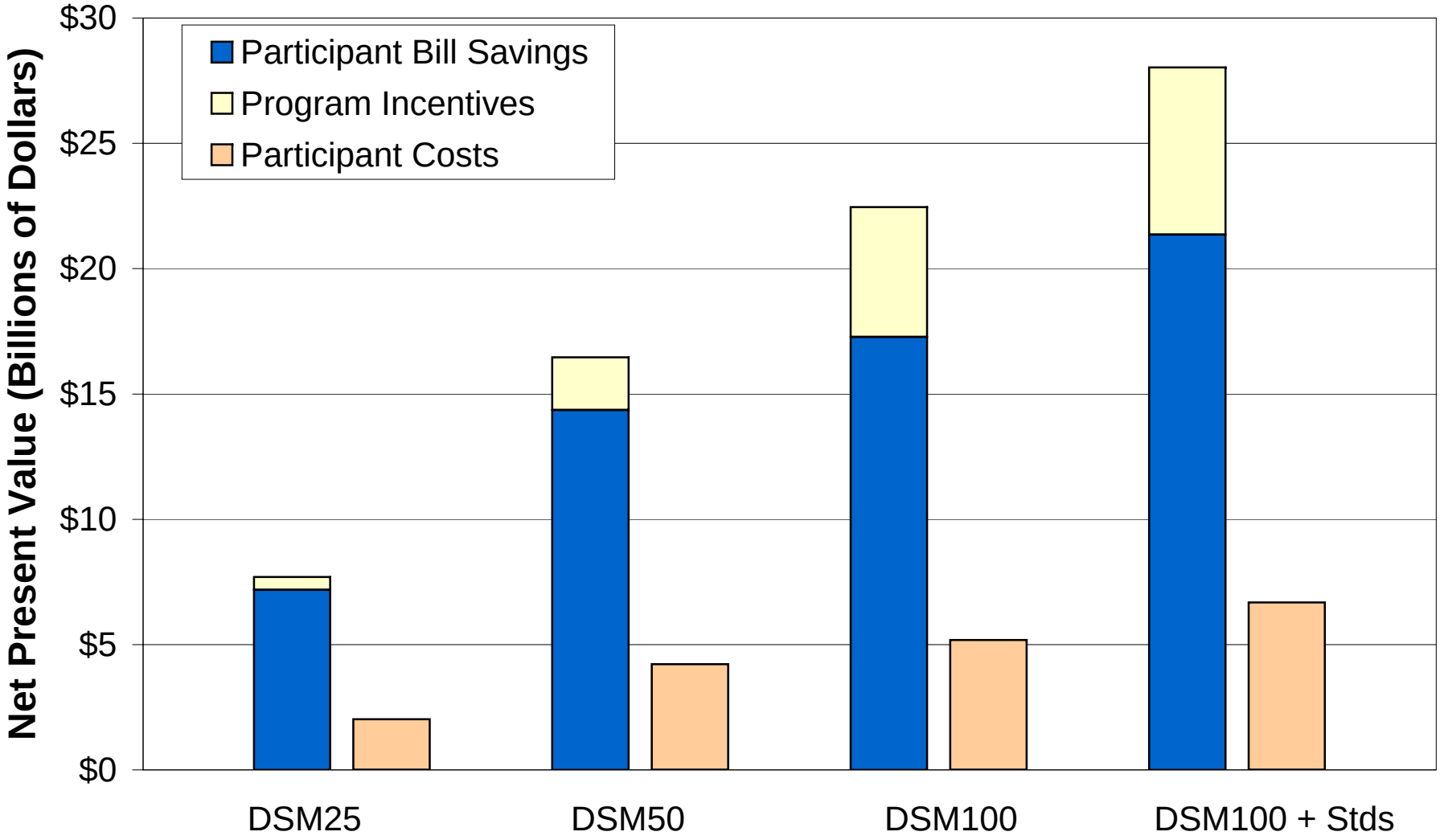
DSM100 Plus Standards	**Participant Net Benefits**	**PCT BCR**	**TRC Net Benefits**	**TRC BCR**	**PAC Net Benefits**	**PAC BCR**	**RIM Net Benefits**	**RIM BCR**
Residential Space Heat	$ 1,537,109	6.04	$ 622,714	2.28	$ 622,714	2.28	$ (914,395)	0.55
Residential Central A/C	$ 512,285	5.95	$ 203,938	2.23	$ 203,938	2.23	$ (308,347)	0.55
Residential Room A/C	$ 35,138	3.75	$ 4,987	1.24	$ 4,987	1.24	$ (30,151)	0.46
Residential Lighting	$ 1,469,583	5.29	$ 513,678	1.94	$ 513,678	1.94	$ (955,906)	0.53
Residential Refrigerator	$ 278,568	0.00	$ 301,923	0.00	$ 301,923	0.00	$ 23,355	1.08
Residential Freezer	$ 159,147	0.00	$ 154,907	0.00	$ 154,907	0.00	$ (4,240)	0.97
Residential Dishwasher	$ 31,222	0.00	$ 22,521	0.00	$ 22,521	0.00	$ (8,700)	0.72
Residential Hot Water	$ 974,819	8.69	$ 502,195	3.48	$ 502,195	3.48	$ (472,623)	0.60
Residential Clothes Dryer	$ 80,142	0.00	$ 120,722	0.00	$ 120,722	0.00	$ 40,580	1.51
Residential Clothes Washer	$ 39,898	3.61	$ 12,785	1.52	$ 12,785	1.52	$ (27,112)	0.58
Commercial Heating	$ 229,749	7.42	$ 131,178	3.29	$ 131,178	3.29	$ (98,572)	0.66
Commercial Ventilation	$ 555,209	5.06	$ 237,138	2.08	$ 237,138	2.08	$ (318,071)	0.59
Commercial Cooling	$ 2,680,376	3.32	$ 343,813	1.19	$ 343,813	1.19	$ (2,336,563)	0.48
Commercial Interior Lighting	$ 4,068,174	2.68	$ (548,764)	0.86	$ (548,764)	0.86	$ (4,616,937)	0.42
Commercial Exterior Lighting	$ 914,264	5.01	$ 396,016	2.09	$ 396,016	2.09	$ (518,248)	0.59
Commercial Refrigeration	$ -	0.00	$ -	0.00	$ -	0.00	$ -	0.00
Commercial Office Equipment	$ 704,012	5.08	$ 299,284	2.08	$ 299,284	2.08	$ (404,729)	0.59
Commercial Hot Water	$ -	0.00	$ -	0.00	$ -	0.00	$ -	0.00
Industrial HVAC	$ 1,860,952	3.69	$ 660,971	1.60	$ 660,971	1.60	$ (1,199,981)	0.60
Industrial Process Cooling	$ 369,457	11.13	$ 291,082	5.99	$ 291,082	5.99	$ (78,375)	0.82
Industrial Process Heating & Boile	$ 2,079,338	7.77	$ 1,476,535	4.00	$ 1,476,535	4.00	$ (602,803)	0.77
Industrial Interior Lighting	$ 490,384	2.63	$ (16,630)	0.97	$ (16,630)	0.97	$ (507,014)	0.48
Industrial Exterior Lighting	$ 148,194	4.36	$ 69,556	1.98	$ 69,556	1.98	$ (78,638)	0.64
Industrial Process Machine Drive	$ 2,135,855	10.12	$ 1,646,361	5.40	$ 1,646,361	5.40	$ (489,494)	0.81
	$ 5,672,012	**3.80**	**$ 6,168,685**	**3.65**	**$ 7,686,153**	**10.50**	**$ 496,673**	**1.06**
Residential	**$ 1,462,214**	**6.38**	**$ 1,281,187**	**5.10**	**$ 1,484,983**	**14.66**	**$ (181,027)**	**0.90**
Commercial	**$ 2,348,805**	**2.78**	**$ 2,071,552**	**2.37**	**$ 3,060,473**	**6.80**	**$ (277,253)**	**0.93**
Industrial	**$ 1,860,993**	**5.30**	**$ 2,815,946**	**6.66**	**$ 3,140,697**	**19.13**	**$ 954,953**	**1.40**


PAC Net Benefits
Net Present Value (Billions of Dollars)
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
Total Benefits (Utility Avoided Costs)
Program Admin & Marketing
Program Incentives
DSM25
DSM50
DSM100
DSM100 + Stds


RIM Net Benefits
Net Present Value (Billions of Dollars)
$35
$30
$25
$20
$15
$10
$5
$0
Total Benefits (Utility Avoided Costs)
Participant Bill Savings (Utility Lost Revenues)
Program Admin & Marketing
Program Incentives
DSM25
DSM50
DSM100
DSM100 + Stds

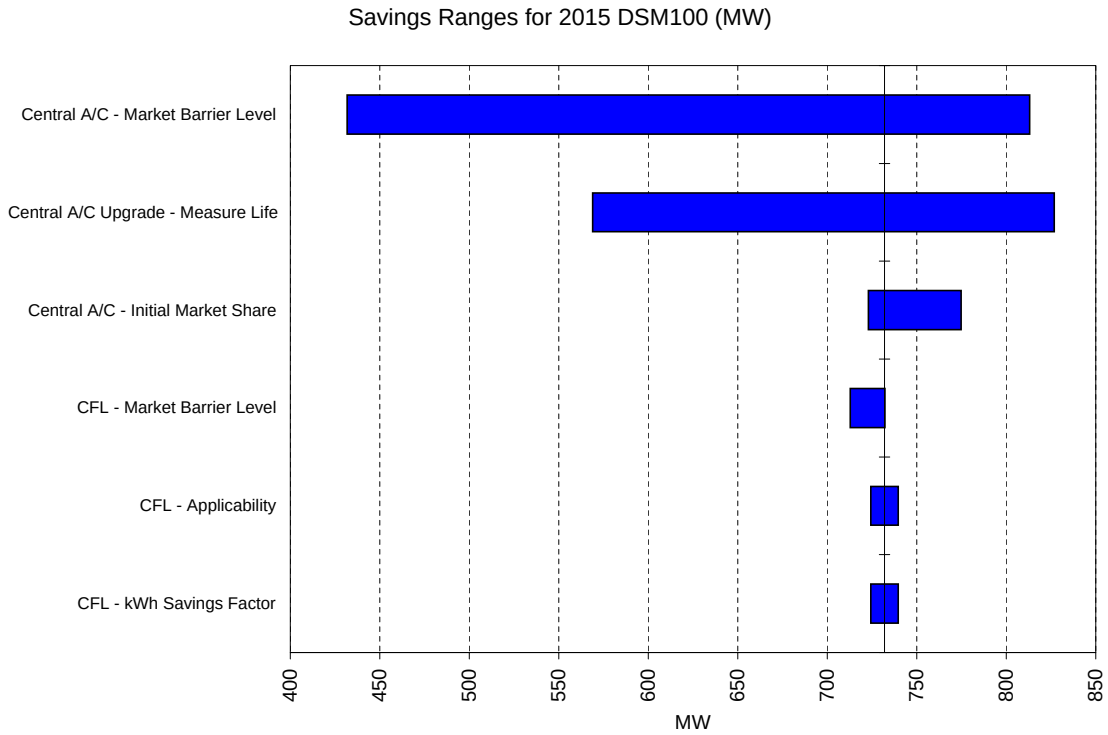

TRC Net Beneifts
Net Present Value (Billions of Dollars)
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
Total Benefits (Utility Avoided Costs)
Program Admin & Marketing
Program Incentives
Participant Costs Less Incentives
DSM25
DSM50
DSM100
DSM100 + Stds

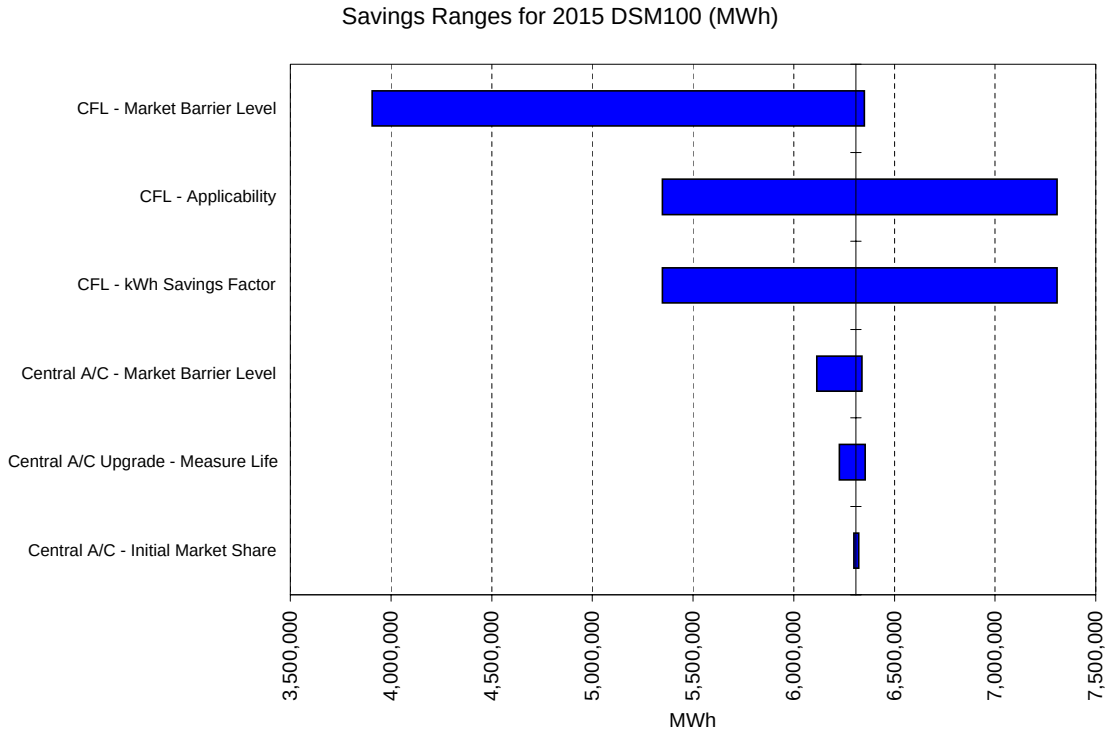
Participant Cost Test Net Benefits



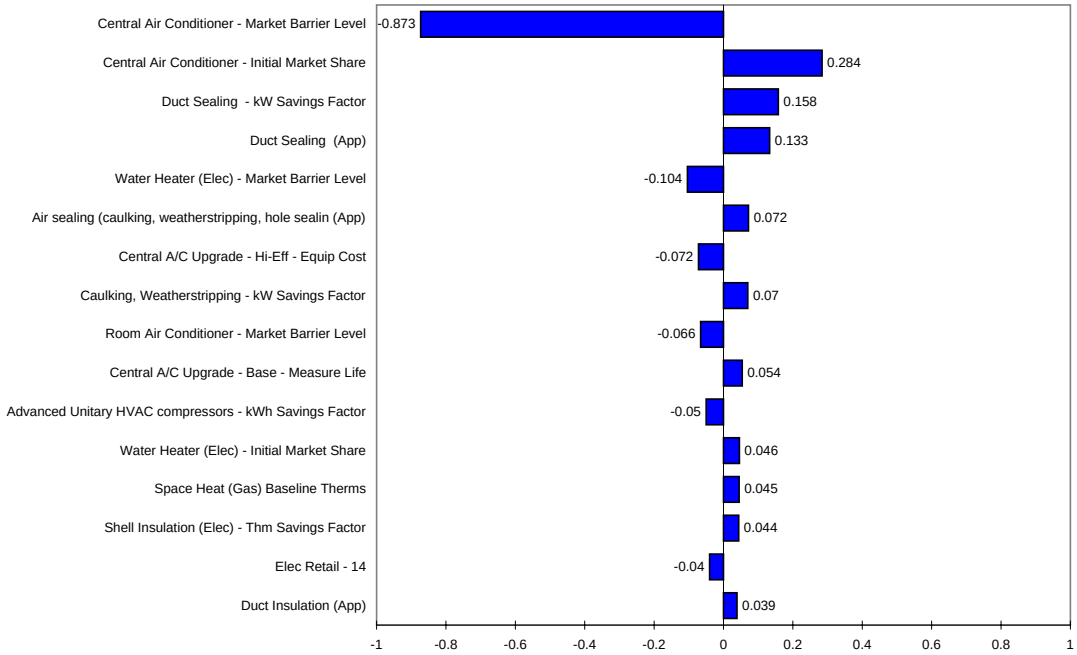
Appendix G

Sensitivity Analysis

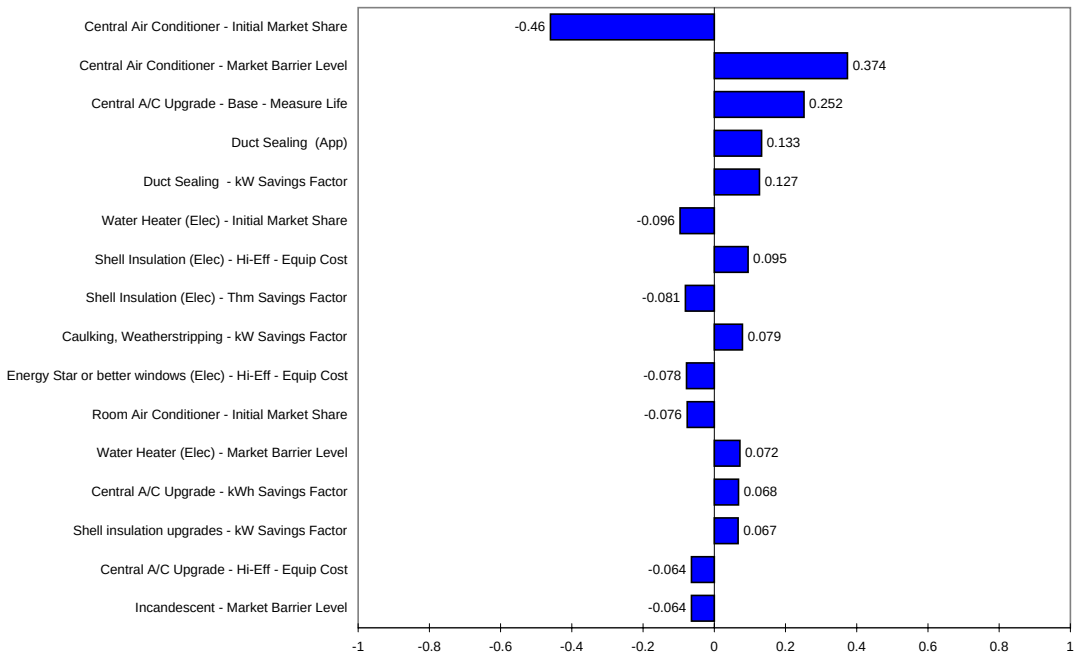

Savings Ranges for 2015 DSM100 (MW)
Central A/C - Market Barrier Level
Central A/C Upgrade - Measure Life
Central A/C - Initial Market Share
CFL - Market Barrier Level
CFL - Applicability
CFL - kWh Savings Factor
400
450
500
550
600
650
700
750
800
850
MW


Savings Ranges for 2015 DSM100 (MWh)
CFL - Market Barrier Level
CFL - Applicability
CFL - kWh Savings Factor
Central A/C - Market Barrier Level
Central A/C Upgrade - Measure Life
Central A/C - Initial Market Share
3,500,000
4,000,000
4,500,000
5,000,000
5,500,000
6,000,000
6,500,000
7,000,000
7,500,000
MWh

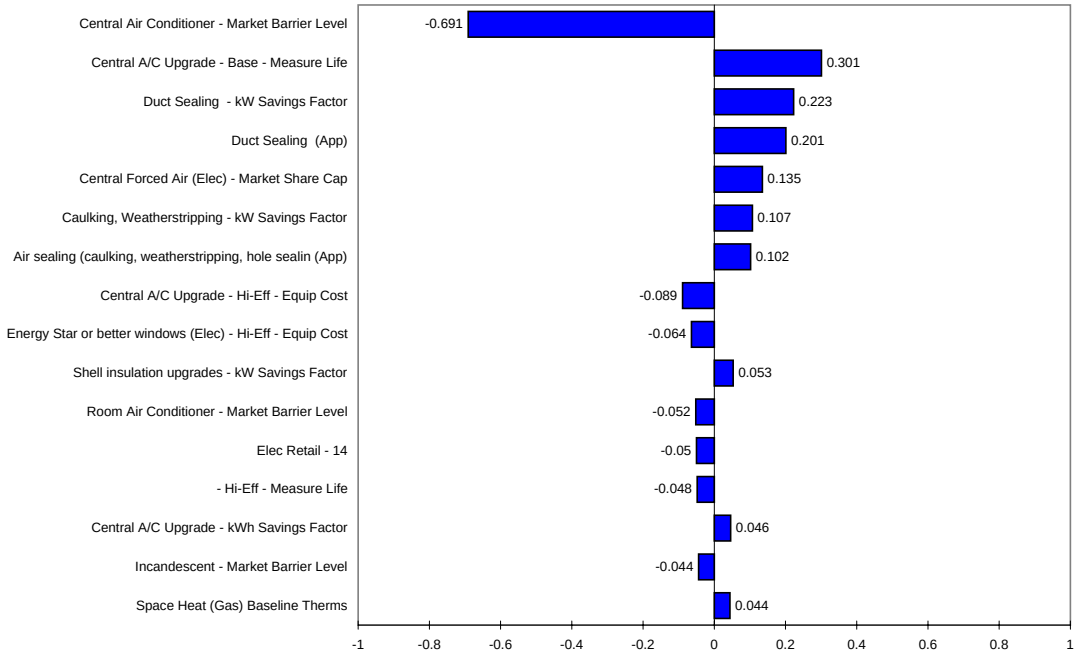
Correlations for DSM25 (MW, 2015)



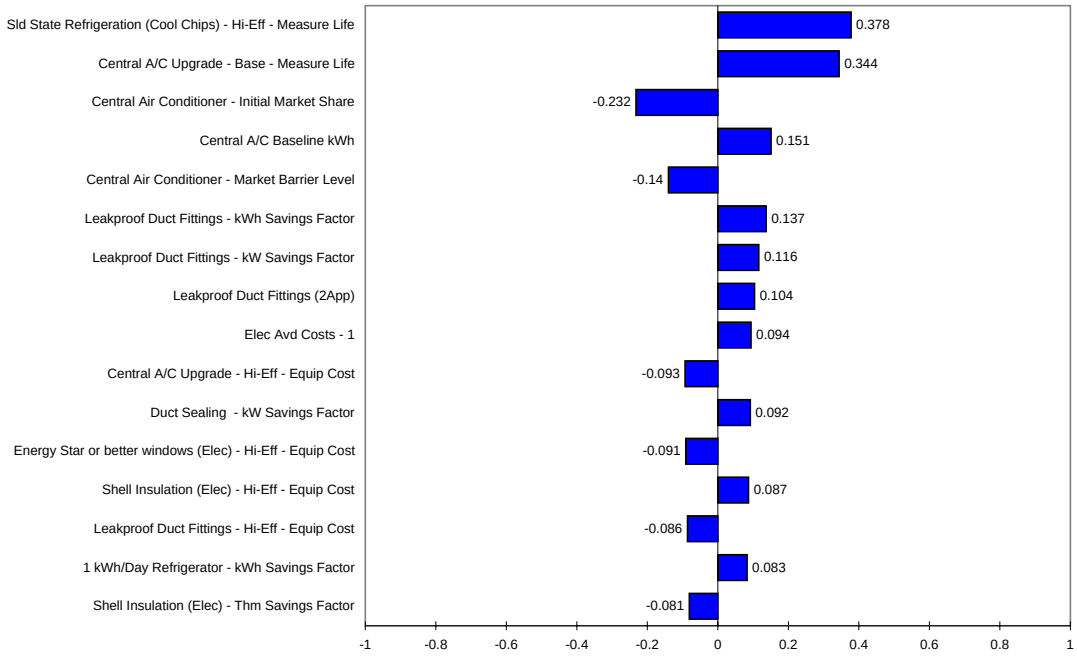
Correlations for DSM25 (MW, 2025)



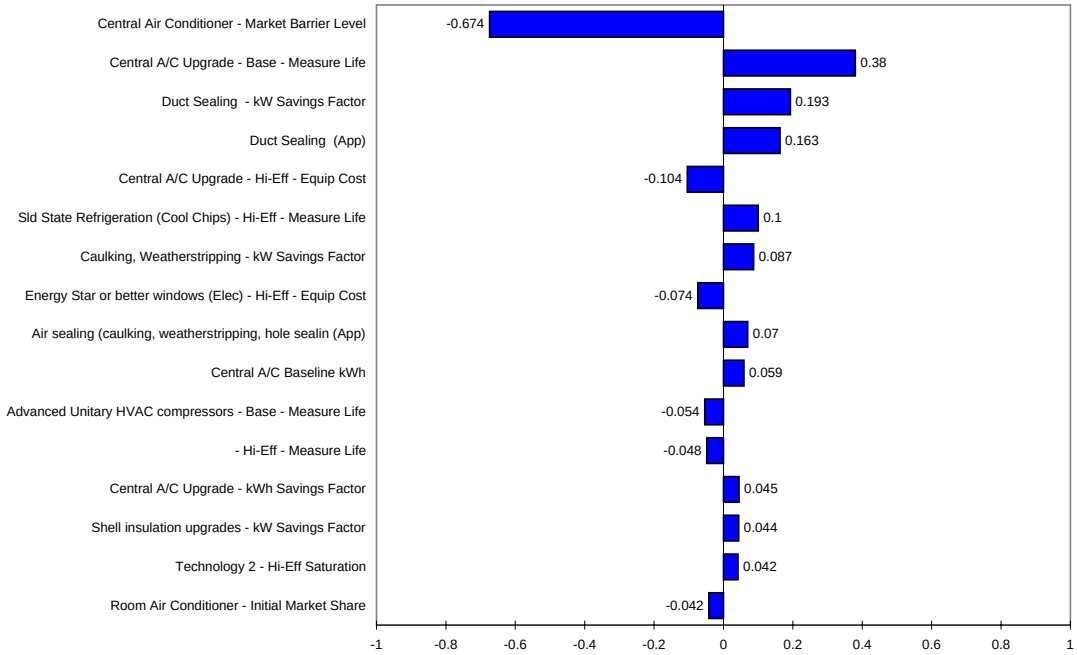
Correlations for DSM50 (MW, 2015)



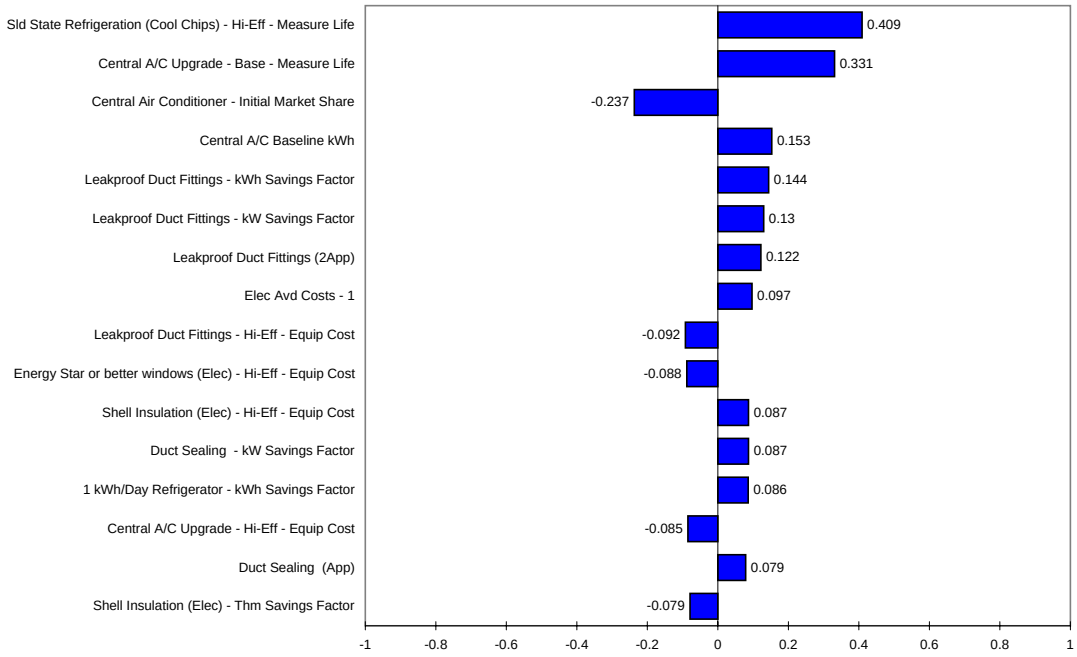
Correlations for DSM50 (MW, 2025)



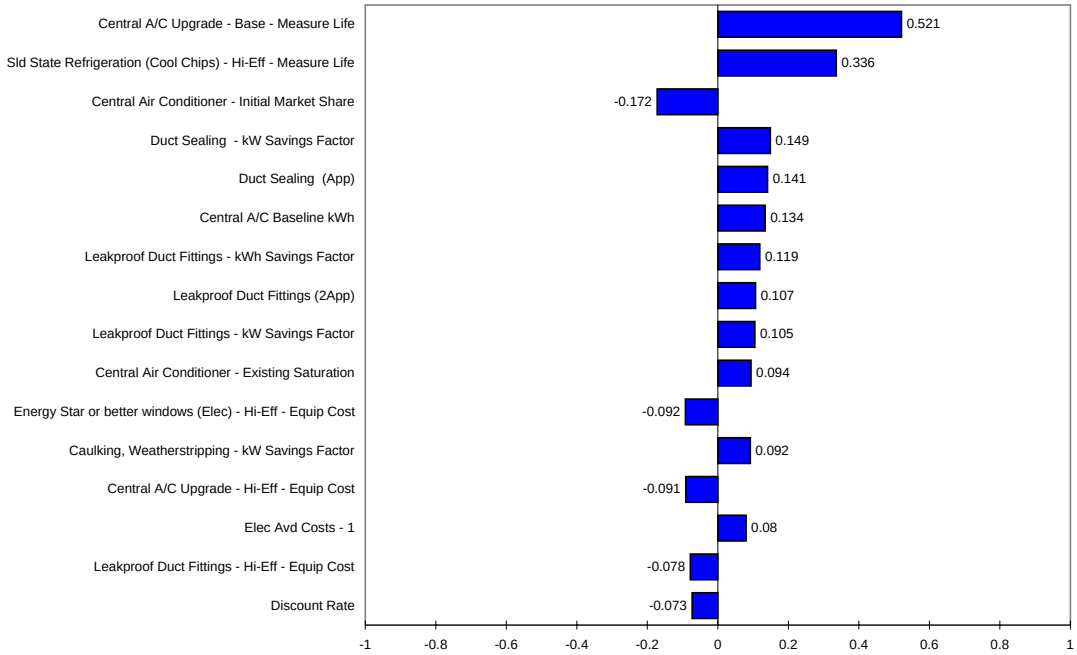
Correlations for DSM100 (MW, 2015)



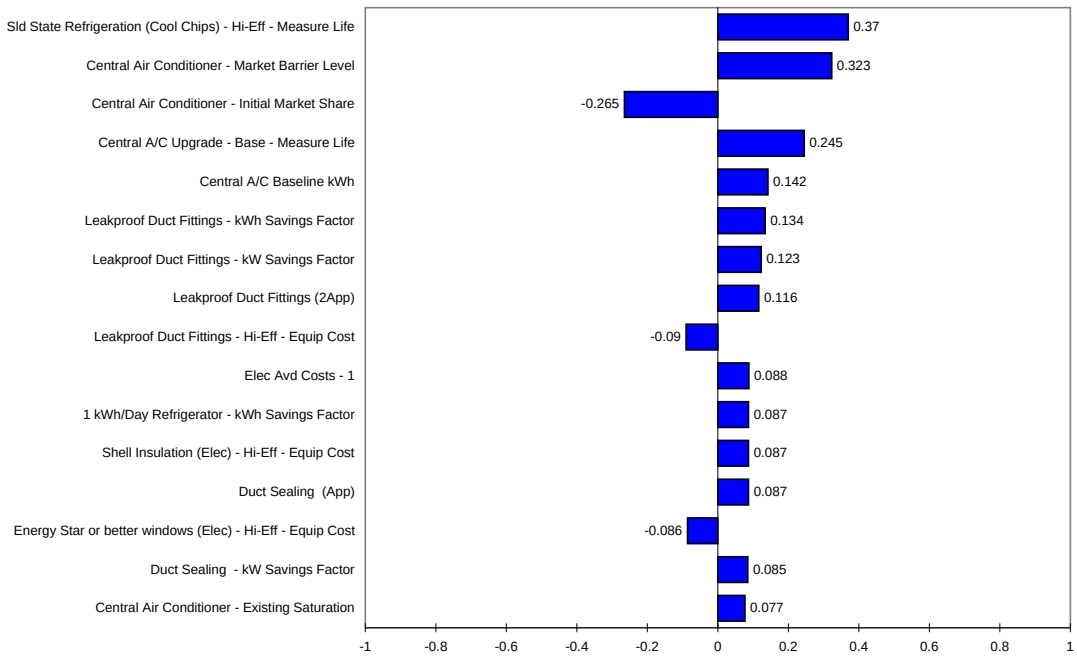
Correlations for DSM100 (MW, 2025)



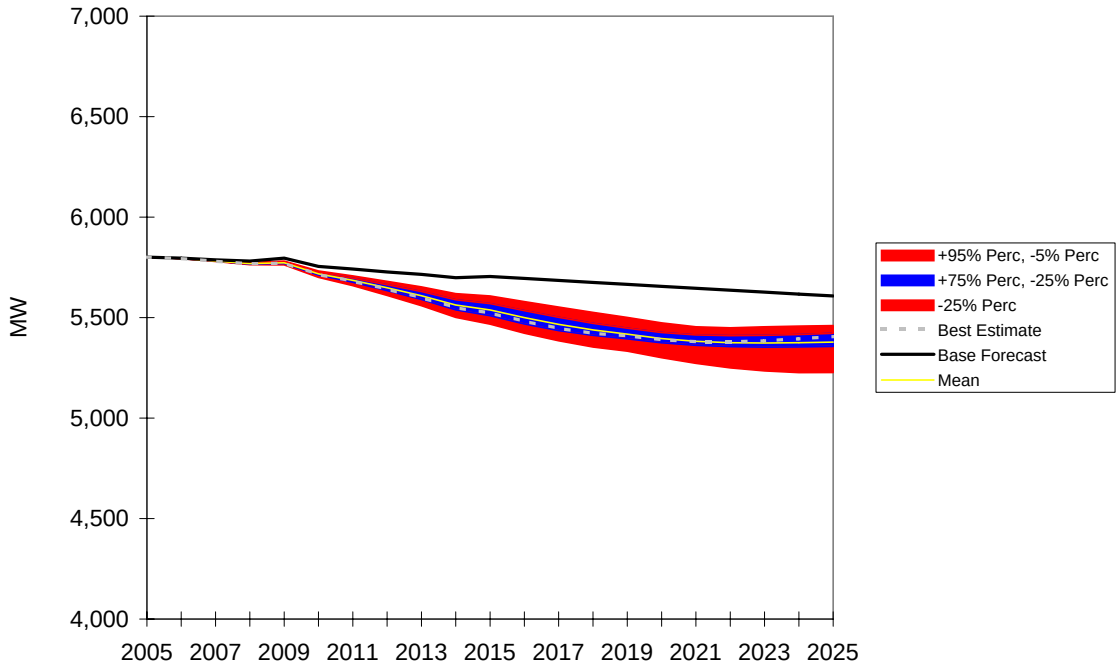
Correlations for DSM100 Plus Standards (MW, 2015)



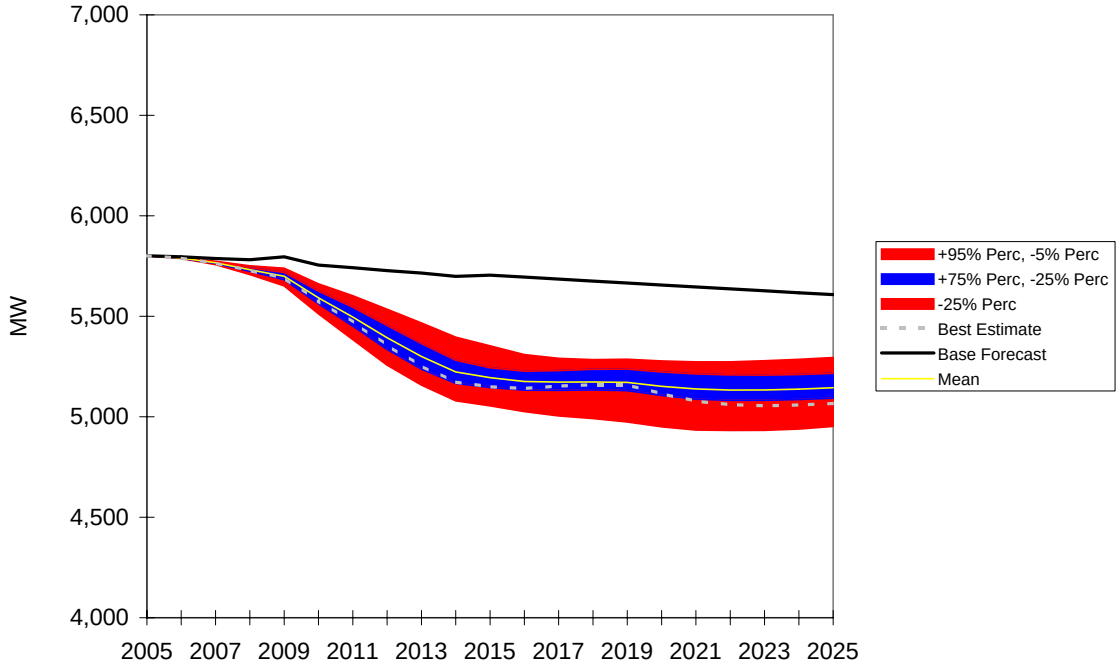
Correlations for DSM100 Plus Standards (MW, 2025)



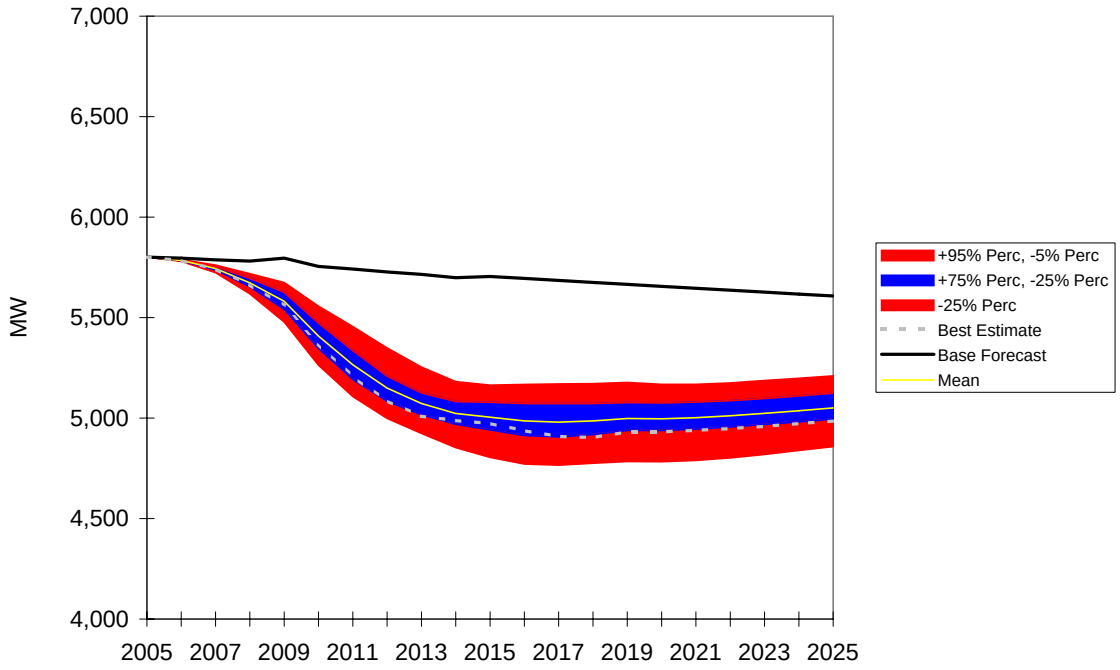
Base Forecast and DSM25 Uncertainty Band (MW)



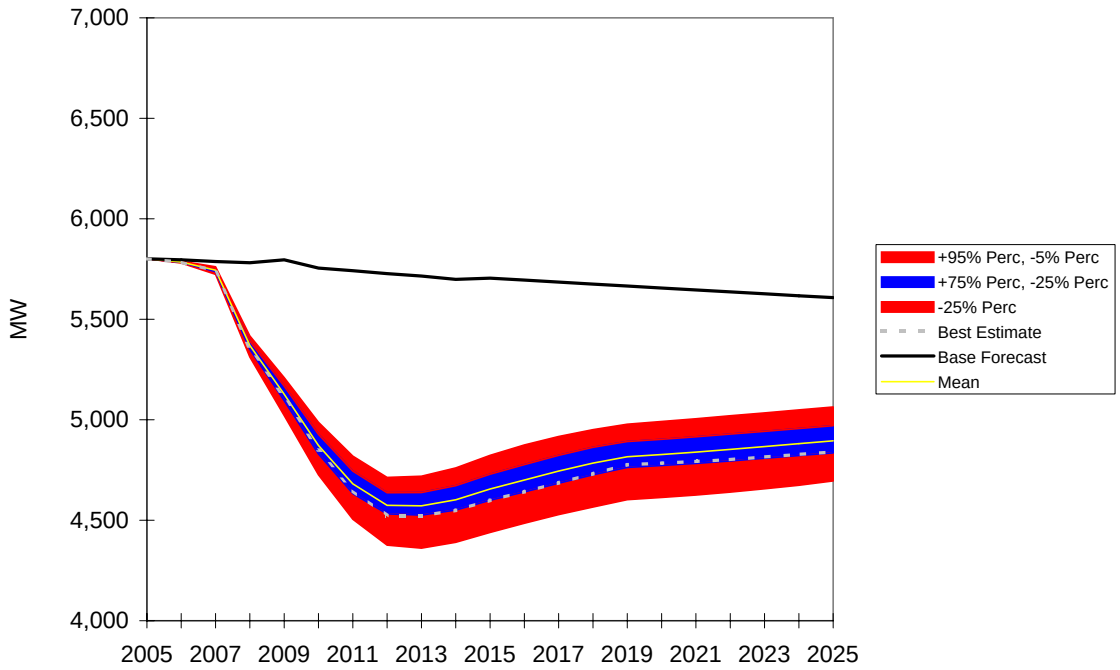
Base Forecast and DSM50 Uncertainty Band (MW)



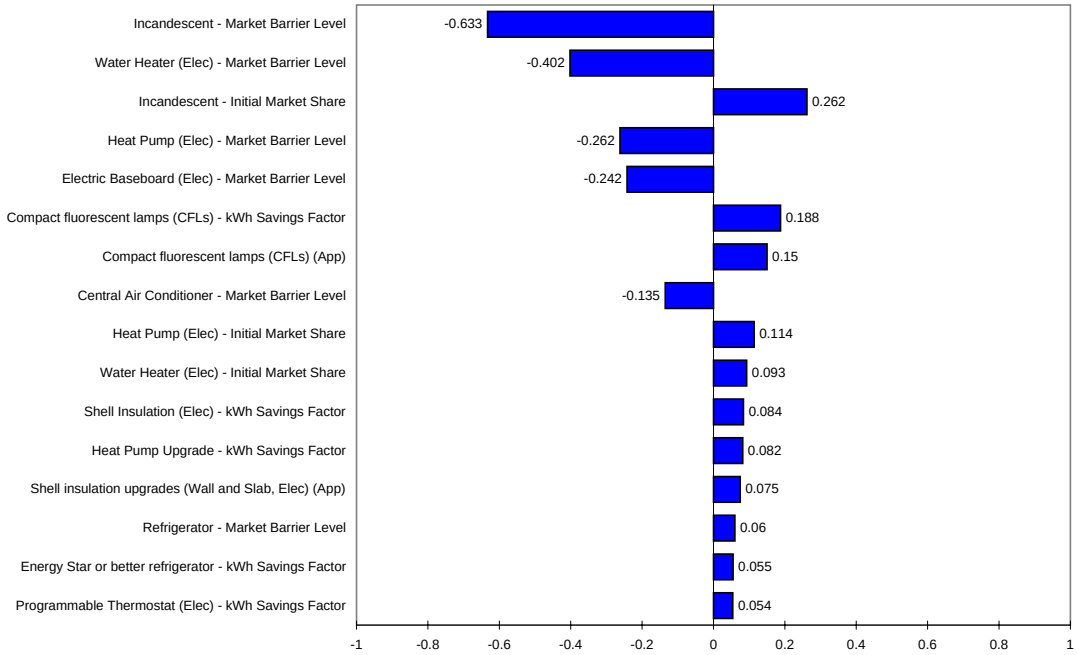
Base Forecast and DSM100 Uncertainty Band (MW)



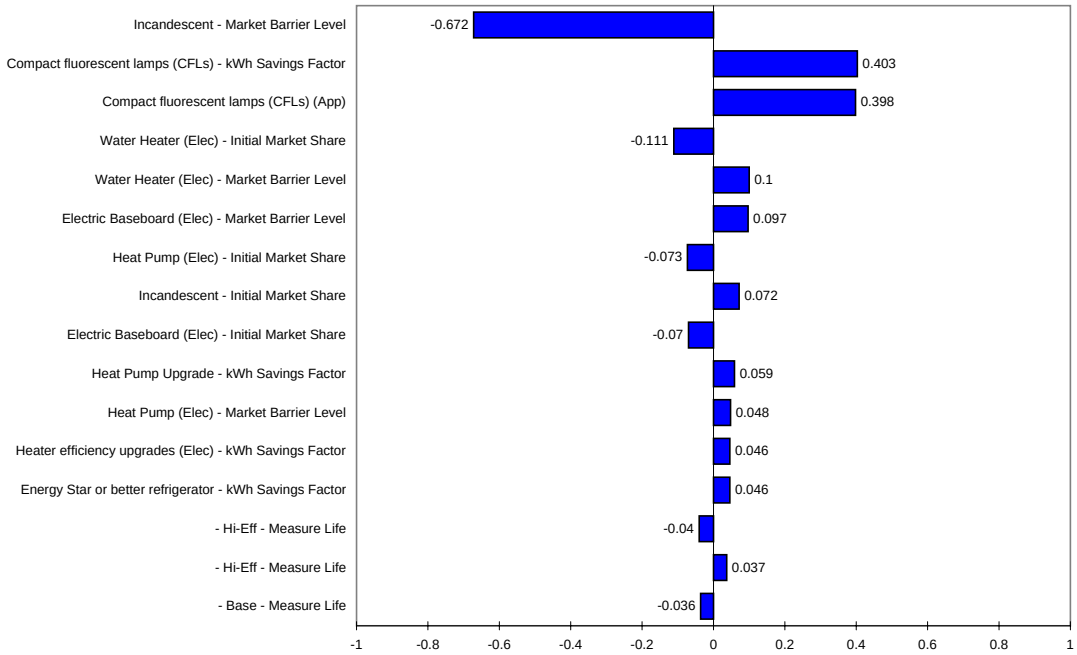
Base Forecast and DSM100 & Stds Uncertainty Band (MW)



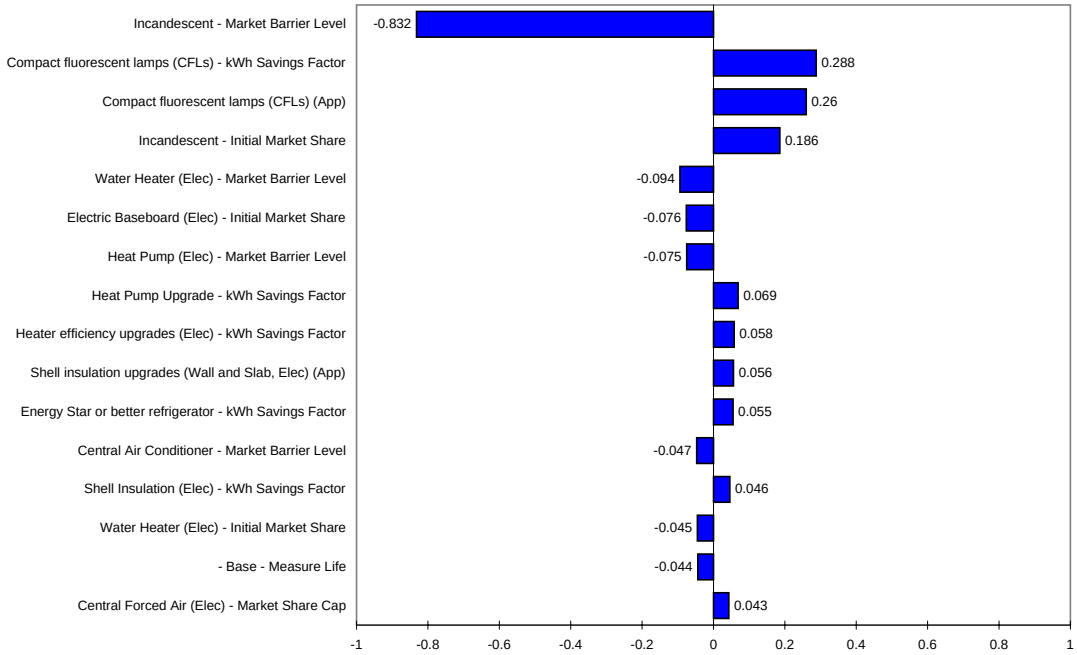
Correlations for DSM25 (MWh, 2015)



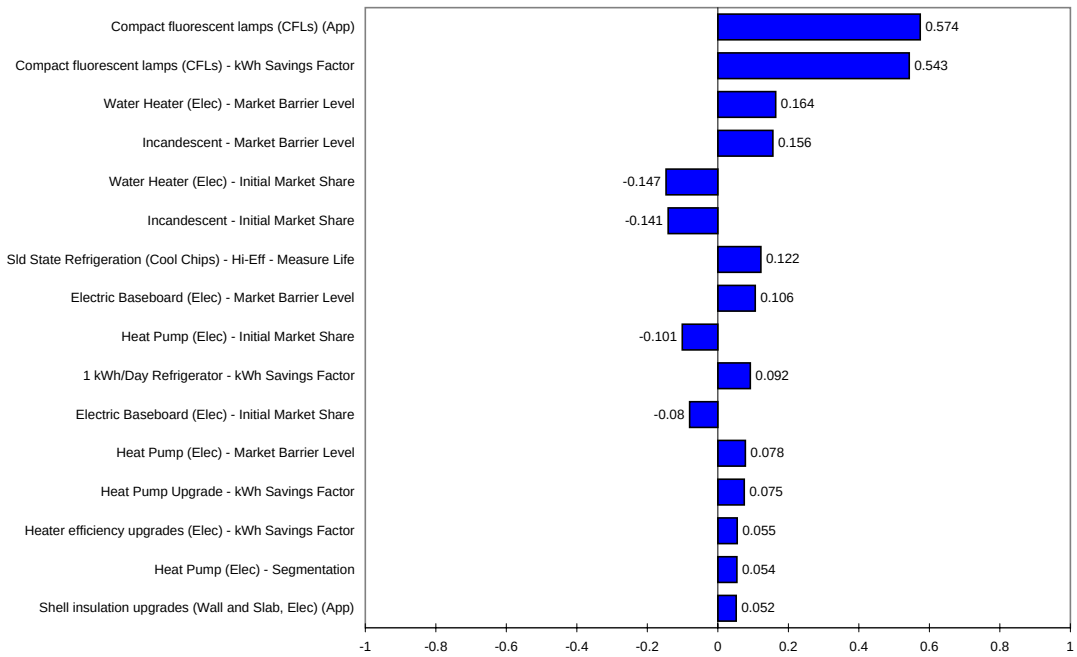
Correlations for DSM25 (MWh, 2025)



Correlations for DSM50 (MWh, 2015)



Correlations for DSM50 (MWh, 2025)



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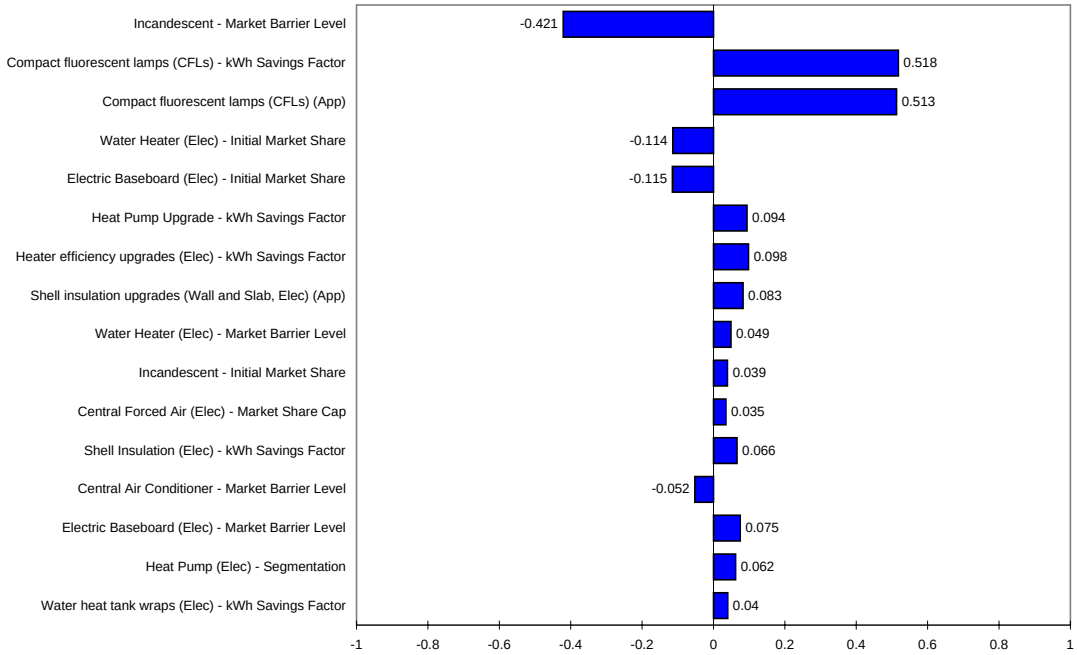
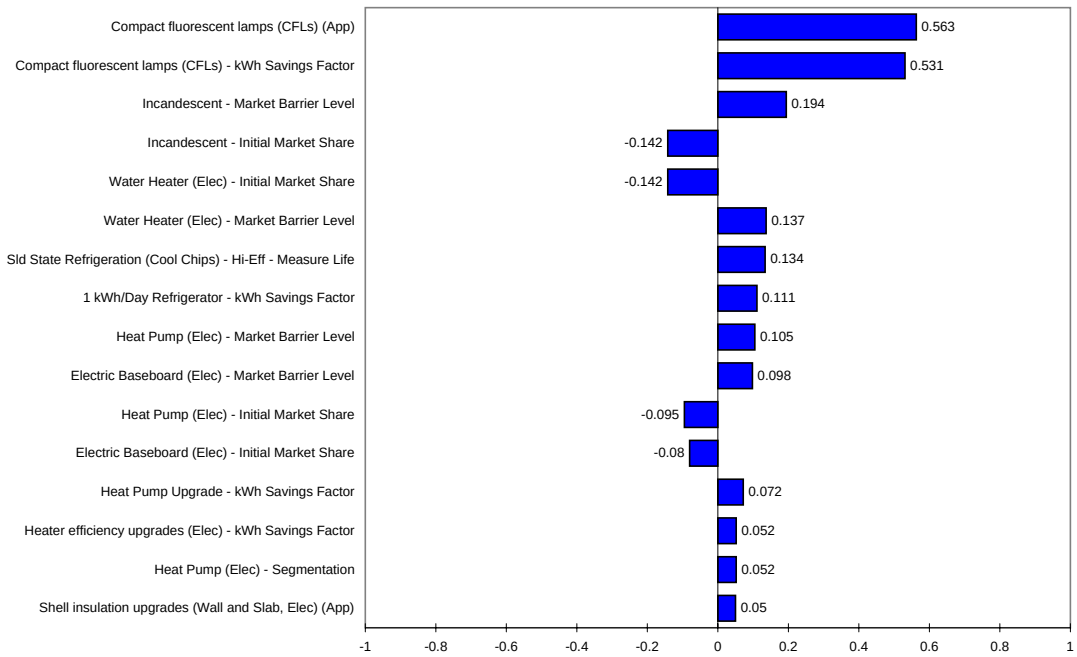
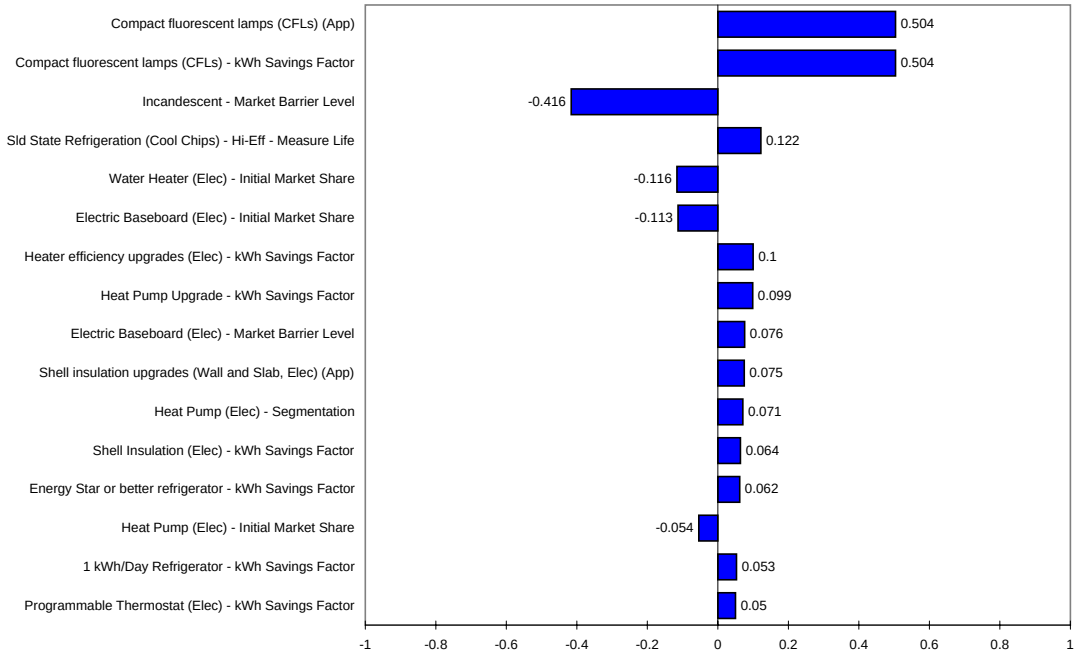


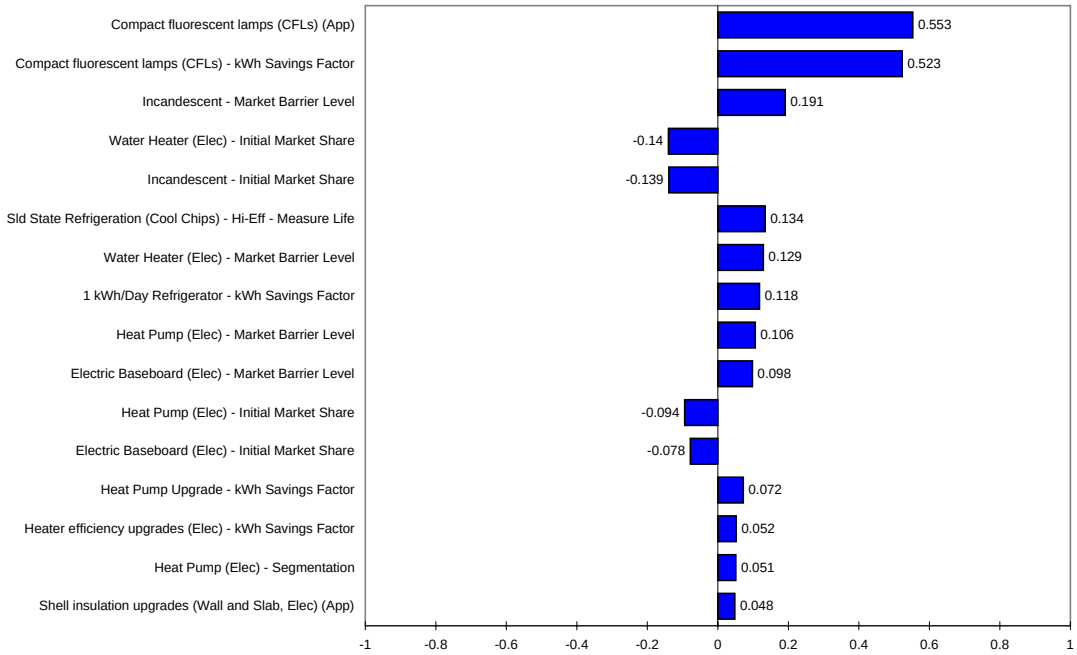
Correlations for DSM100 (MWh, 2025)



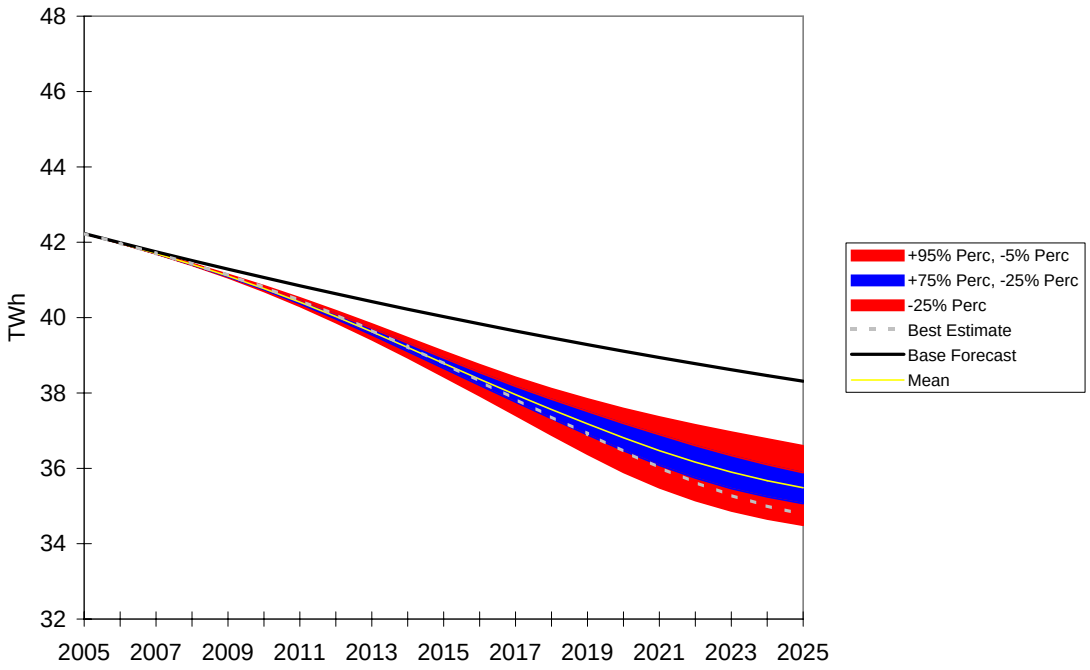
Correlations for DSM100 Plus Standards (MWh, 2015)



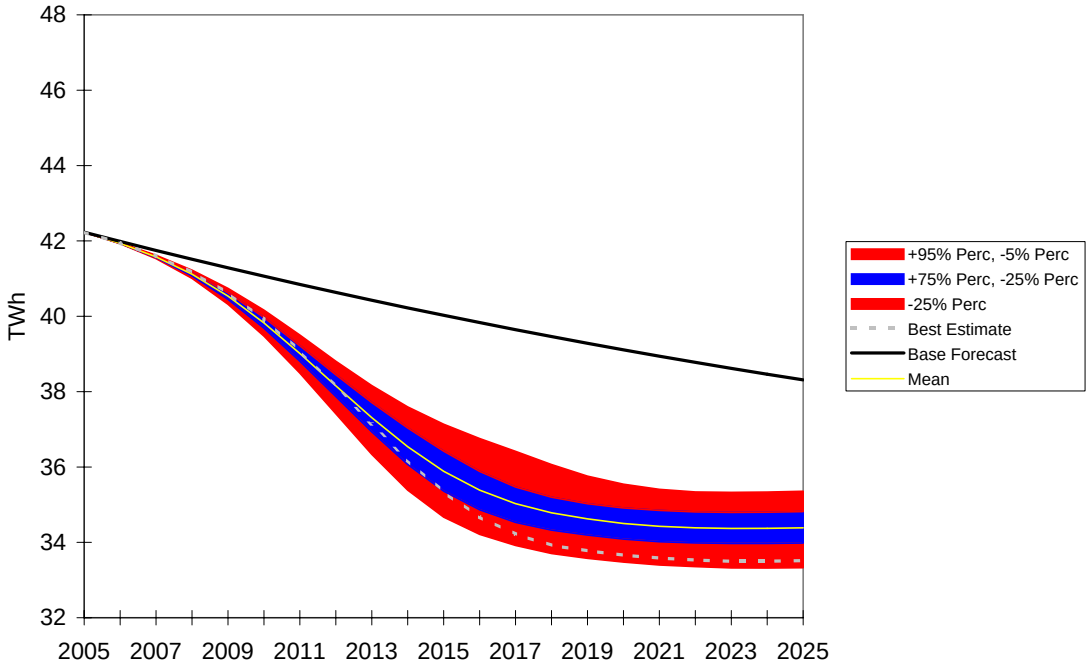
Correlations for DSM100 Plus Standards (MWh, 2025)



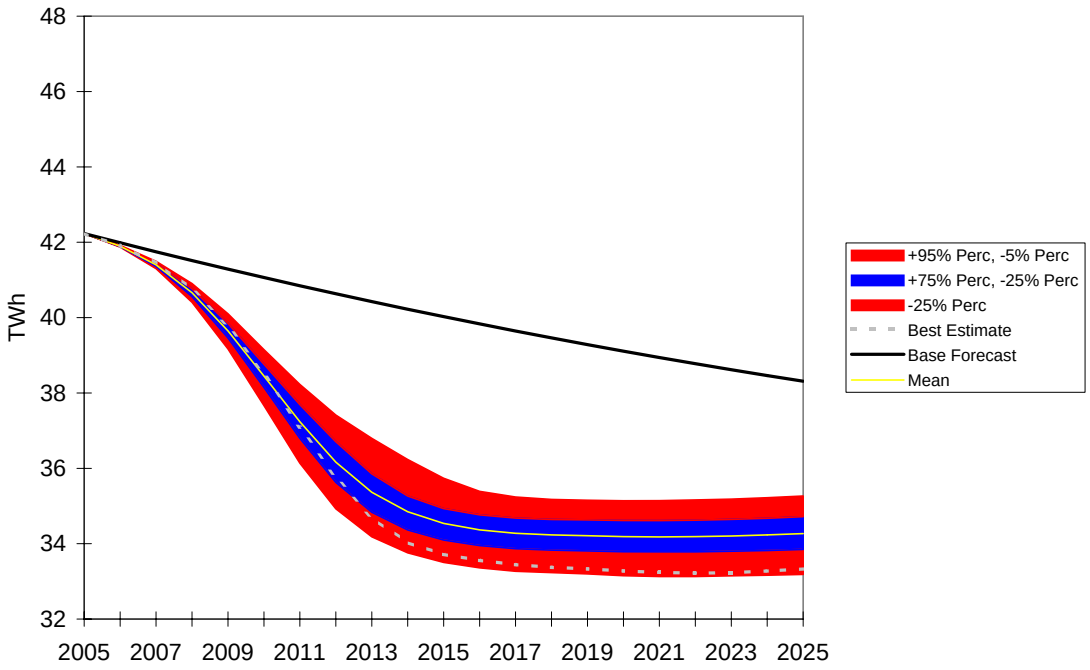
Base Forecast and DSM25 Uncertainty Band (TWh)



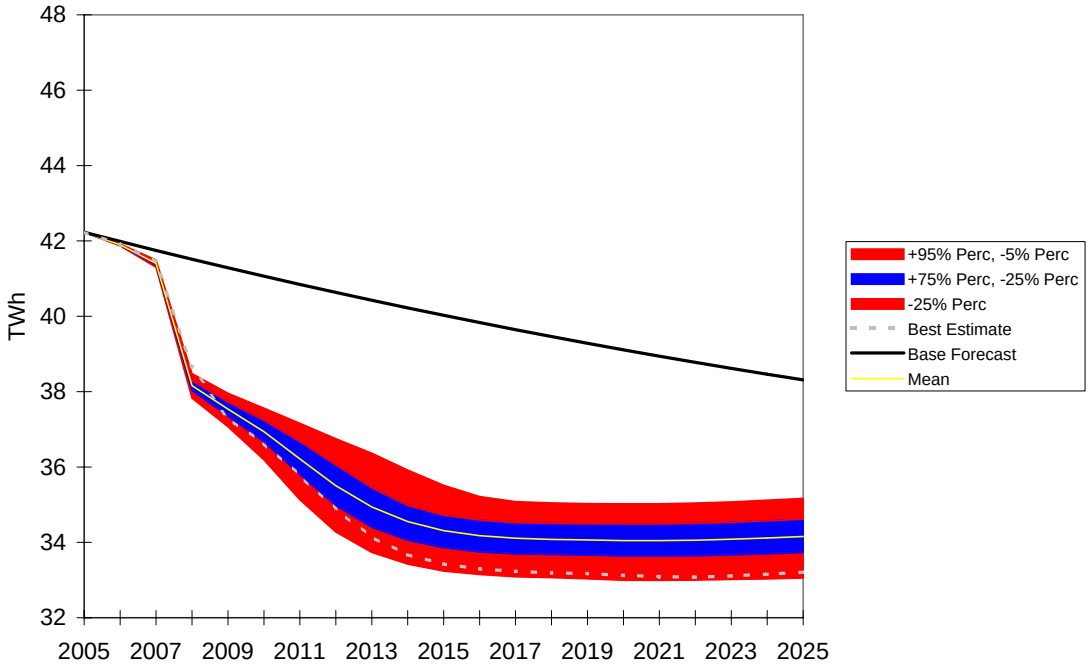
Base Forecast and DSM50 Uncertainty Band (TWh)



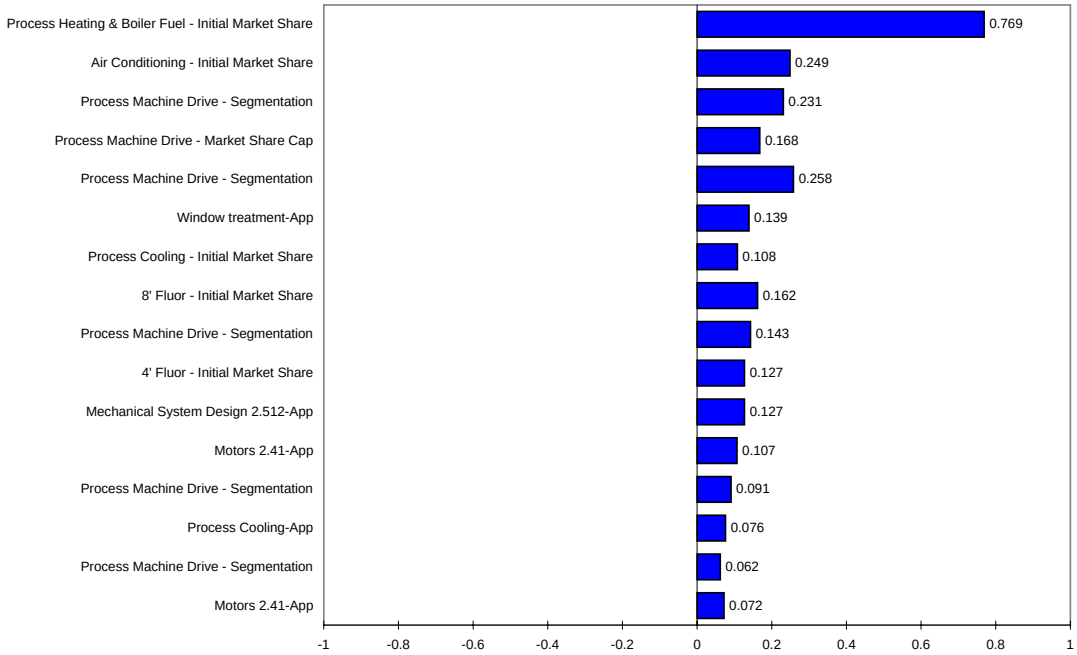
Base Forecast and DSM100 Uncertainty Band (TWh)



Base Forecast and DSM100 & Stds Uncertainty Band (TWh)



Correlations for DSM25 (MW, 2015)



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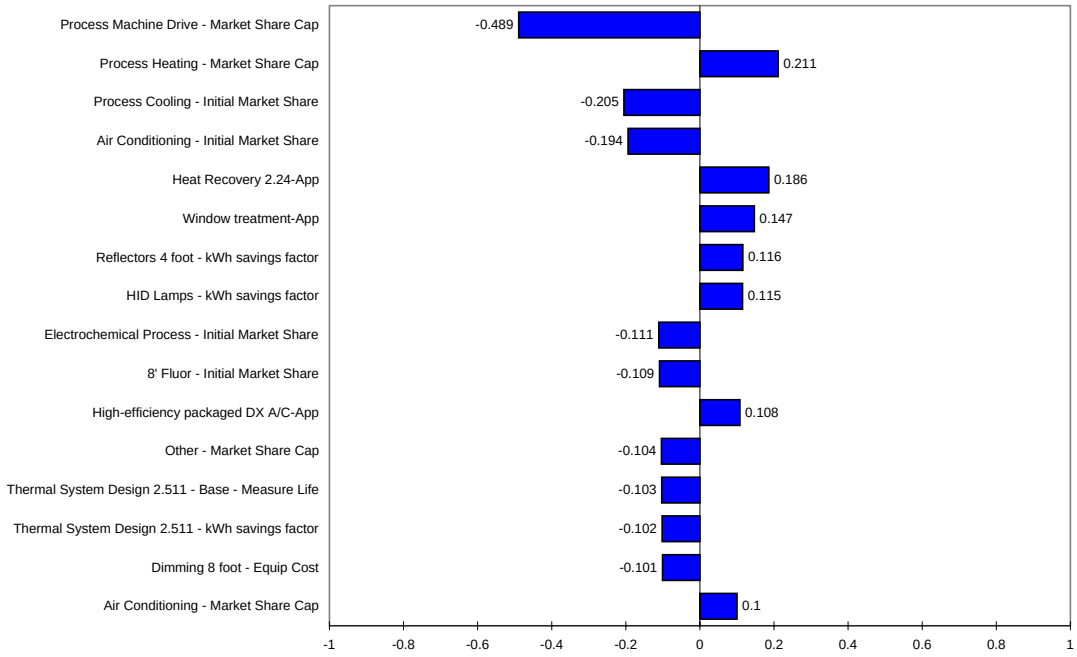

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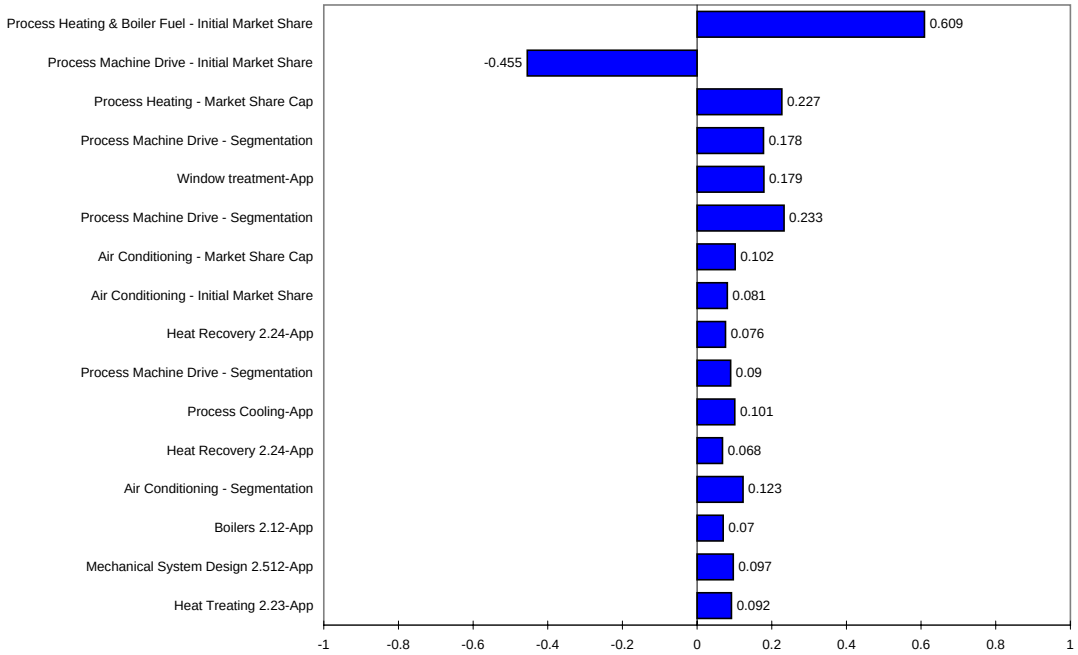

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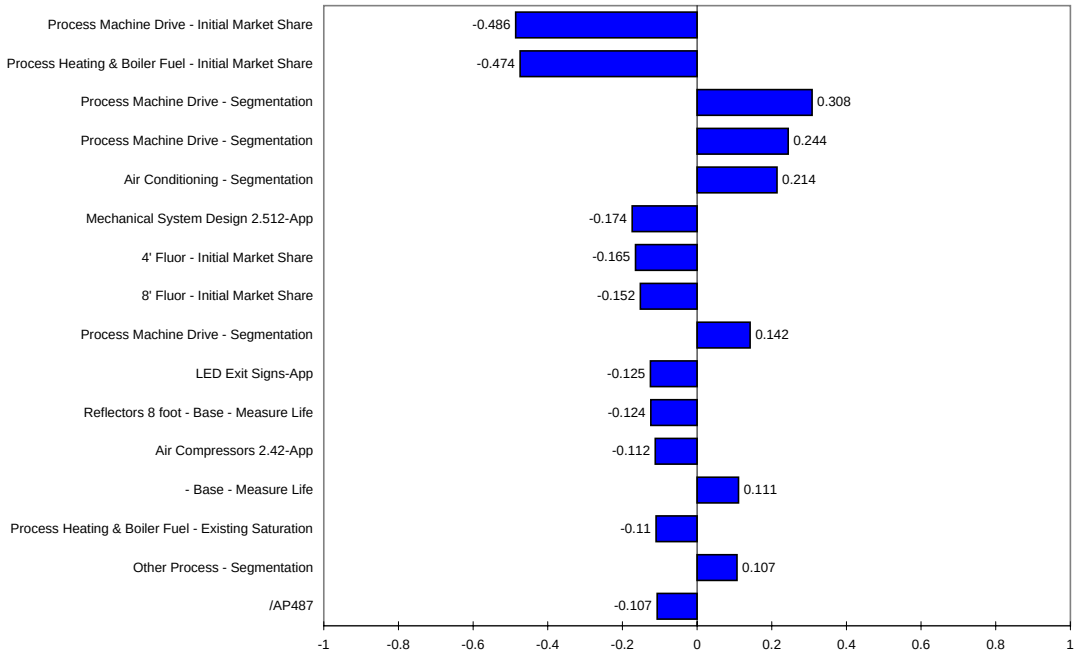

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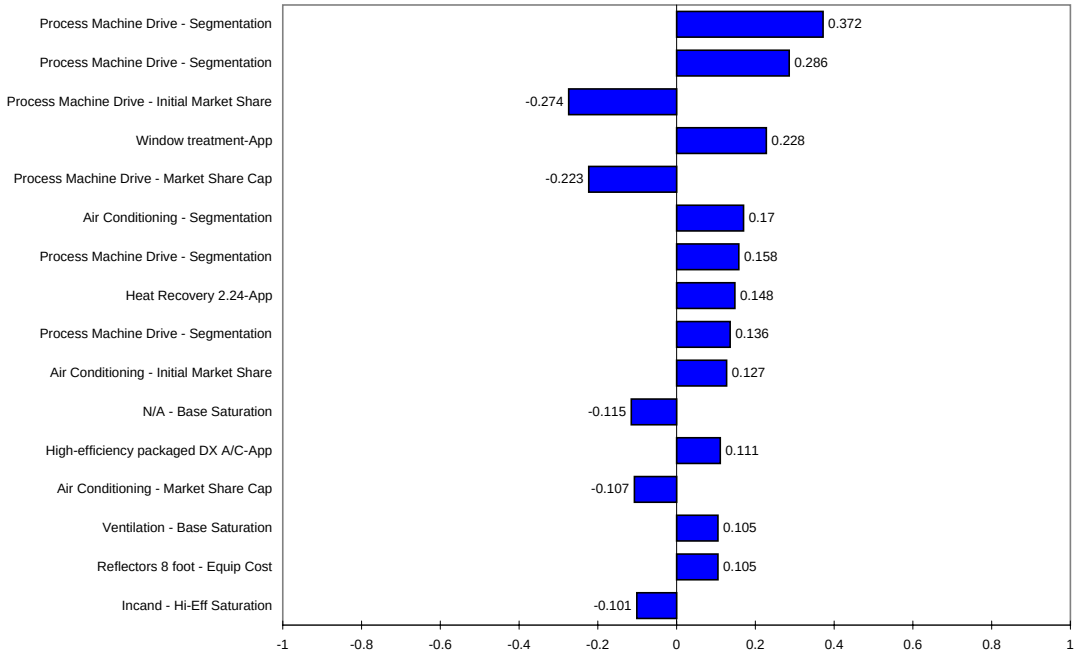

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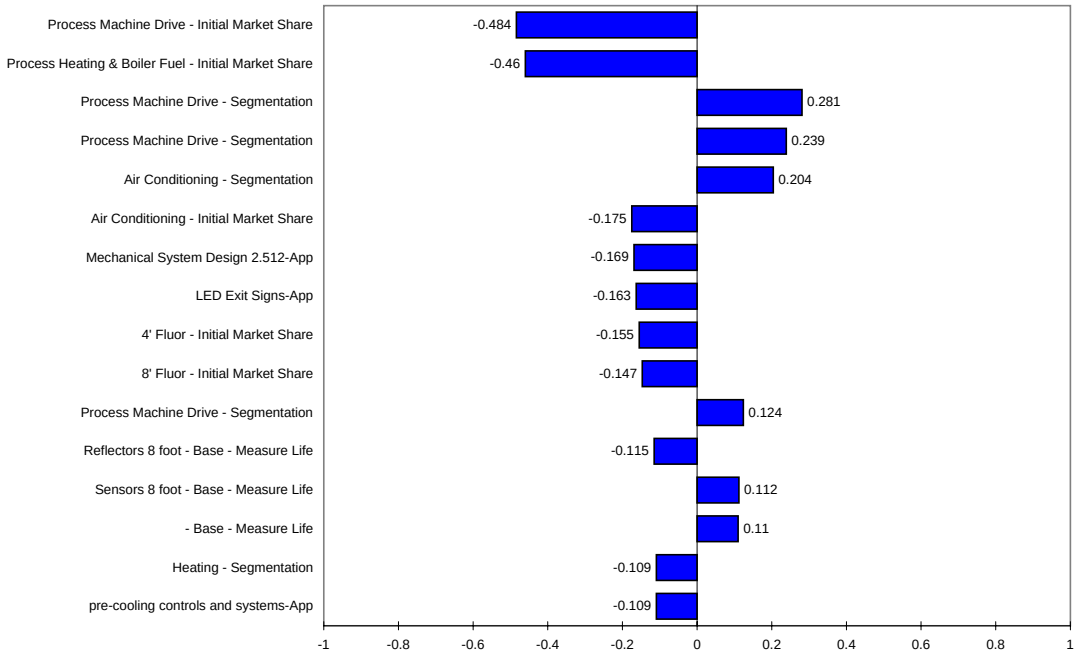

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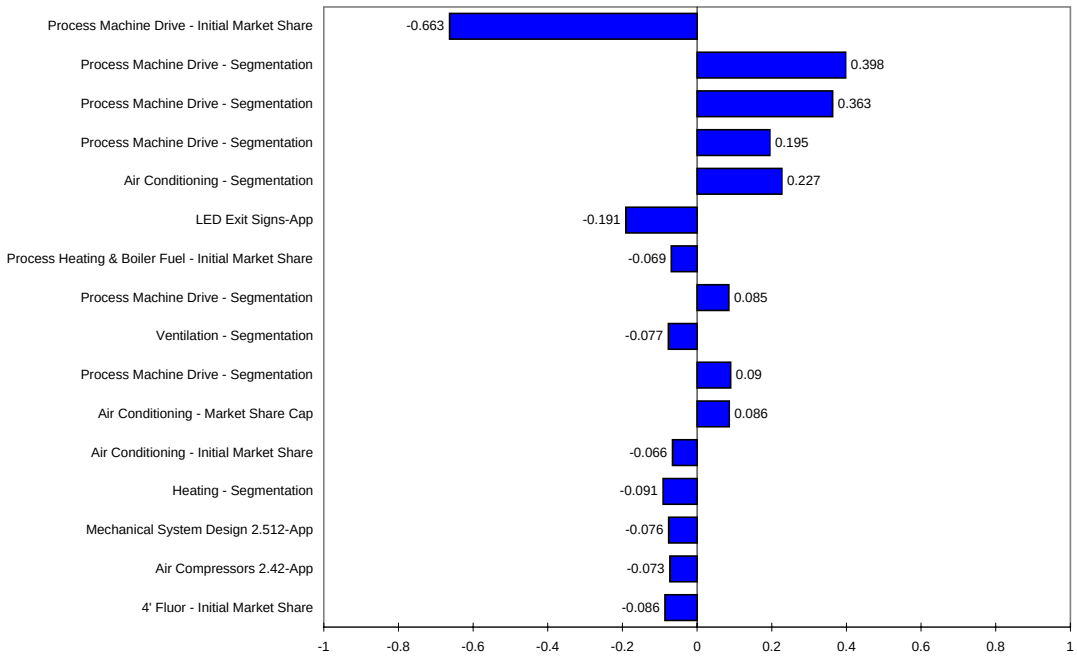

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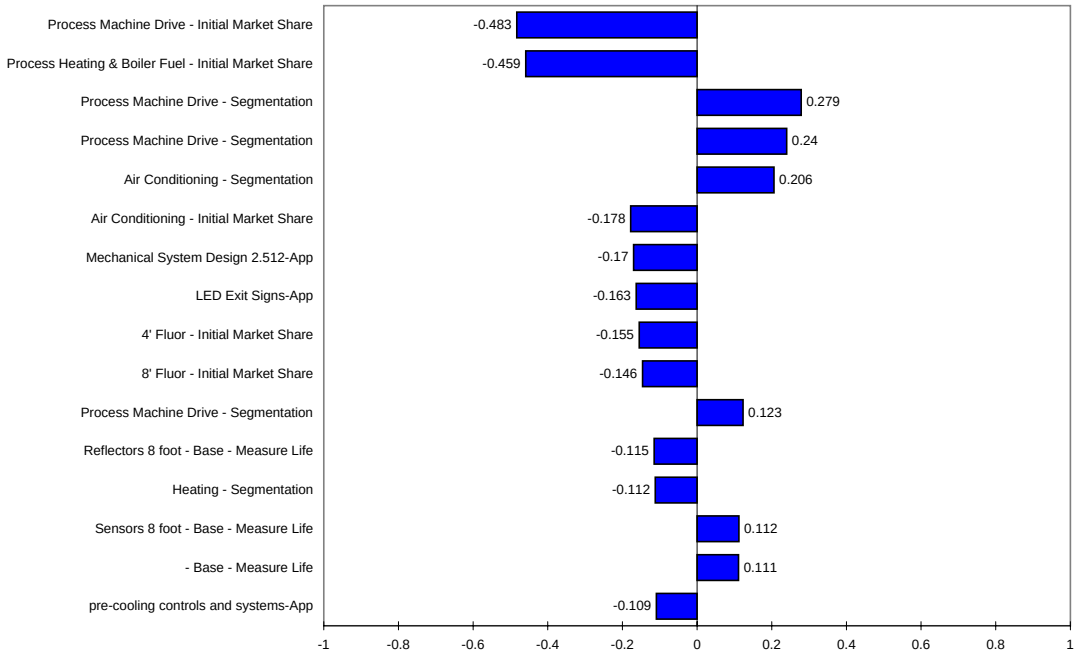

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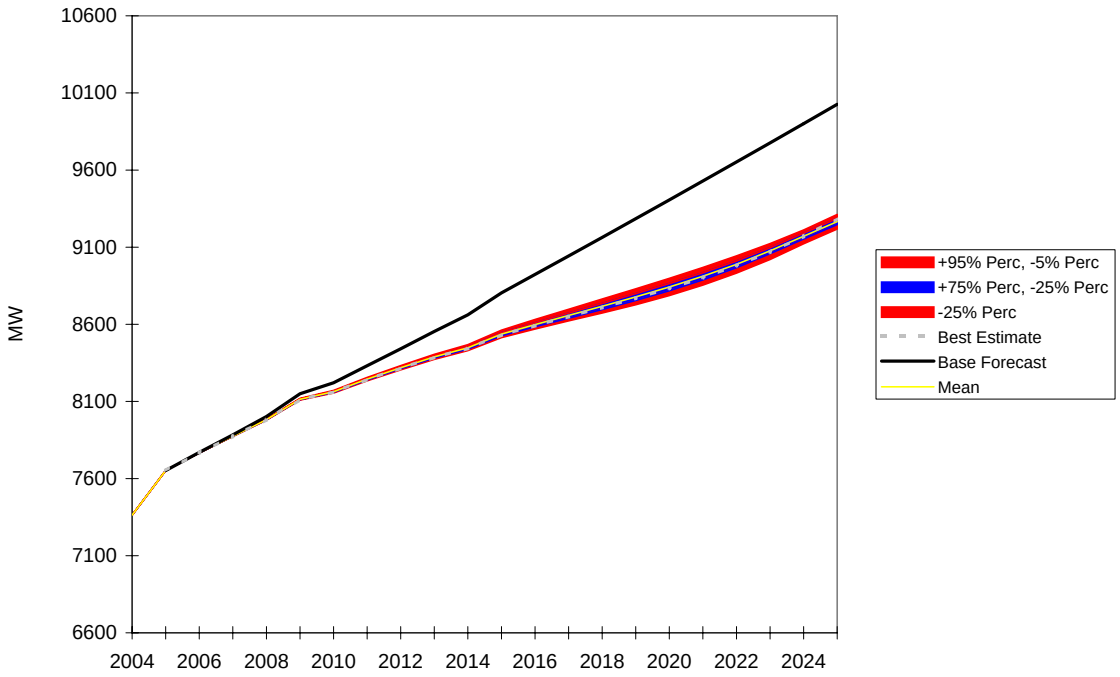

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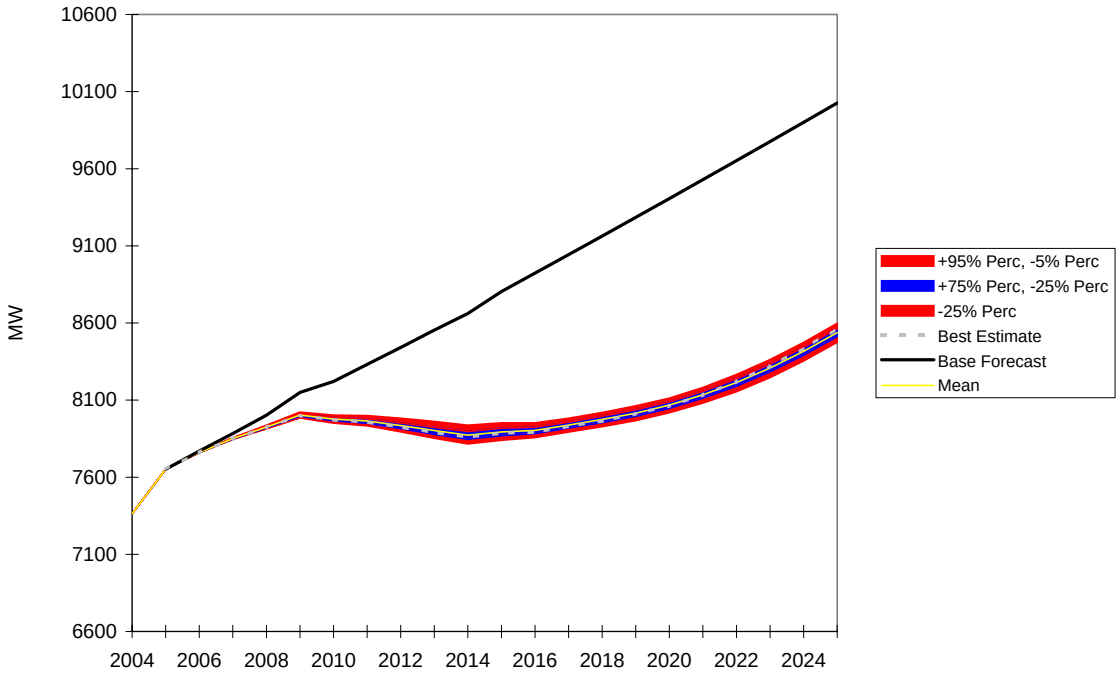

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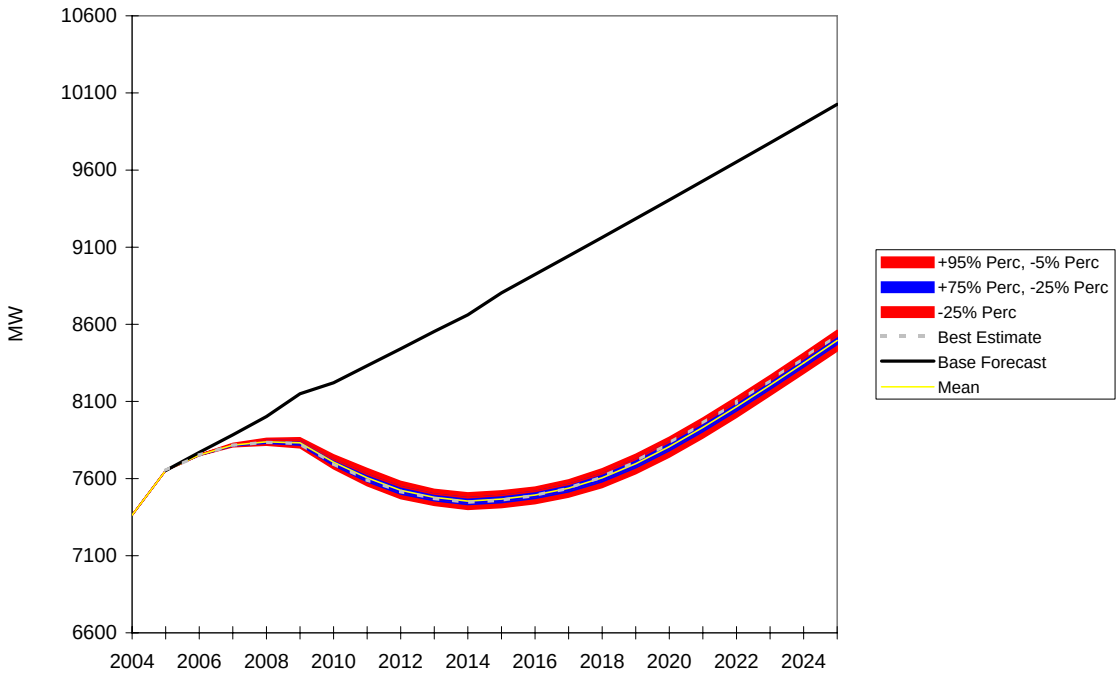

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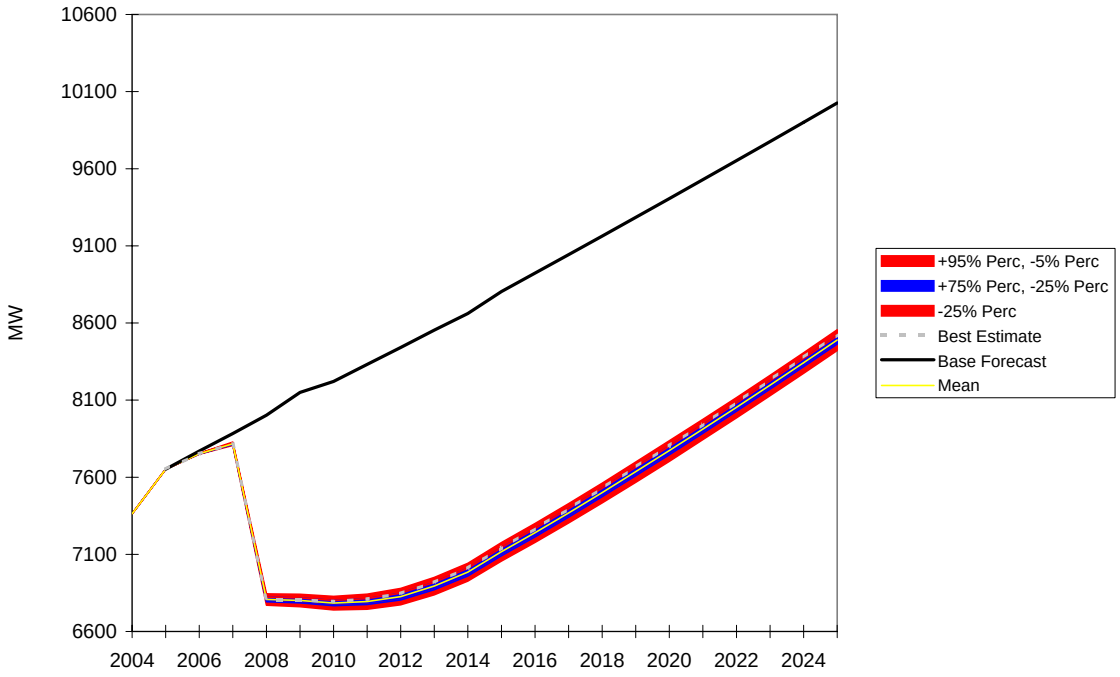

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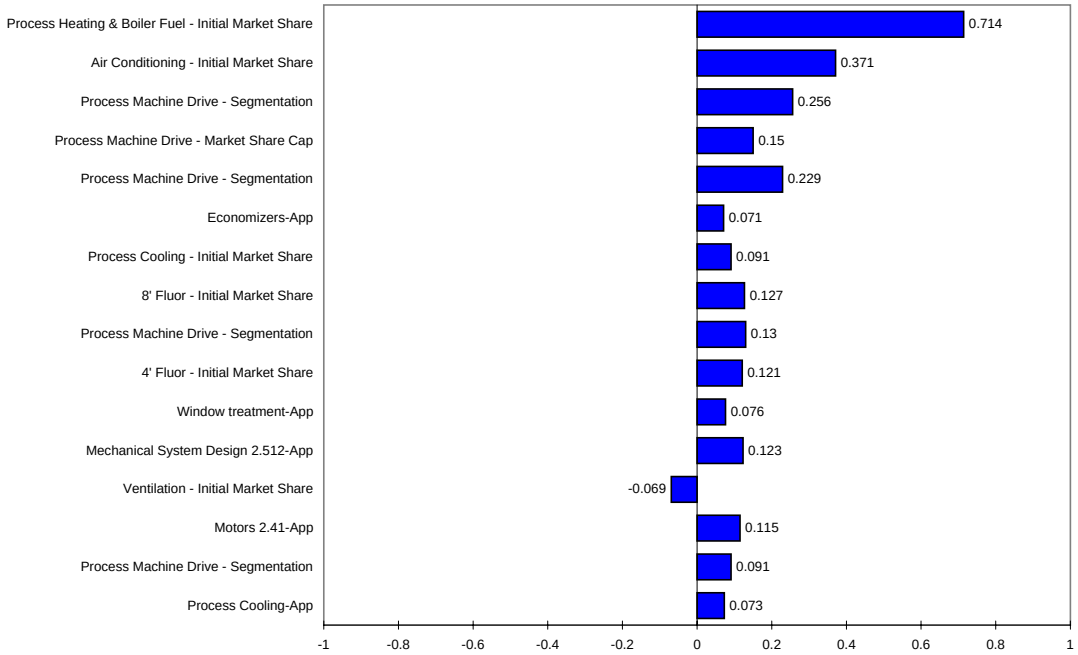

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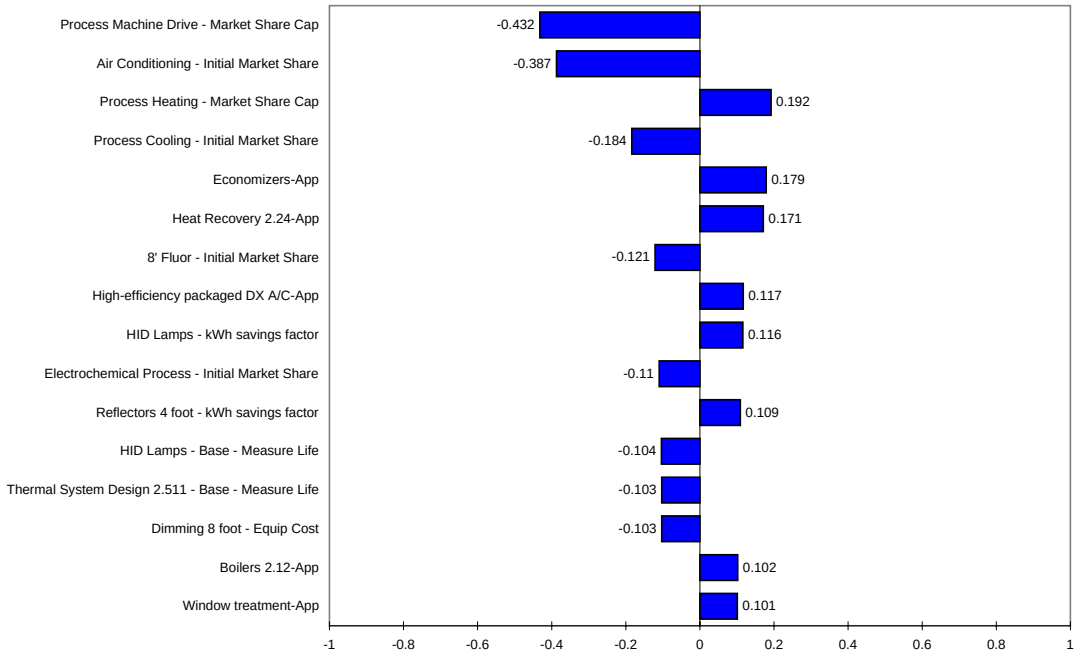

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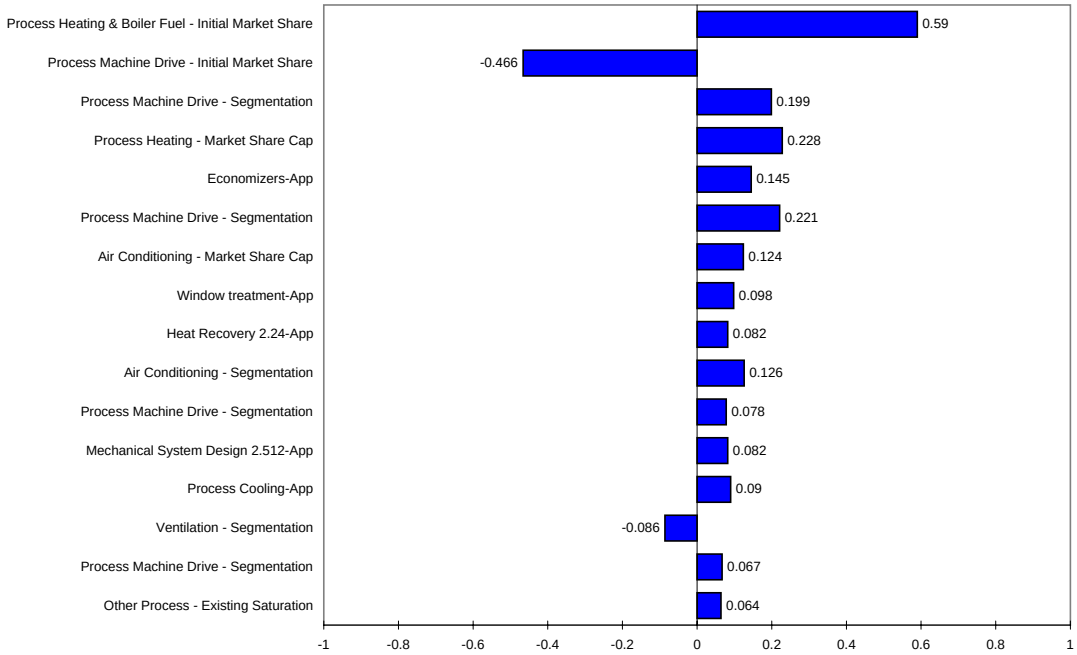

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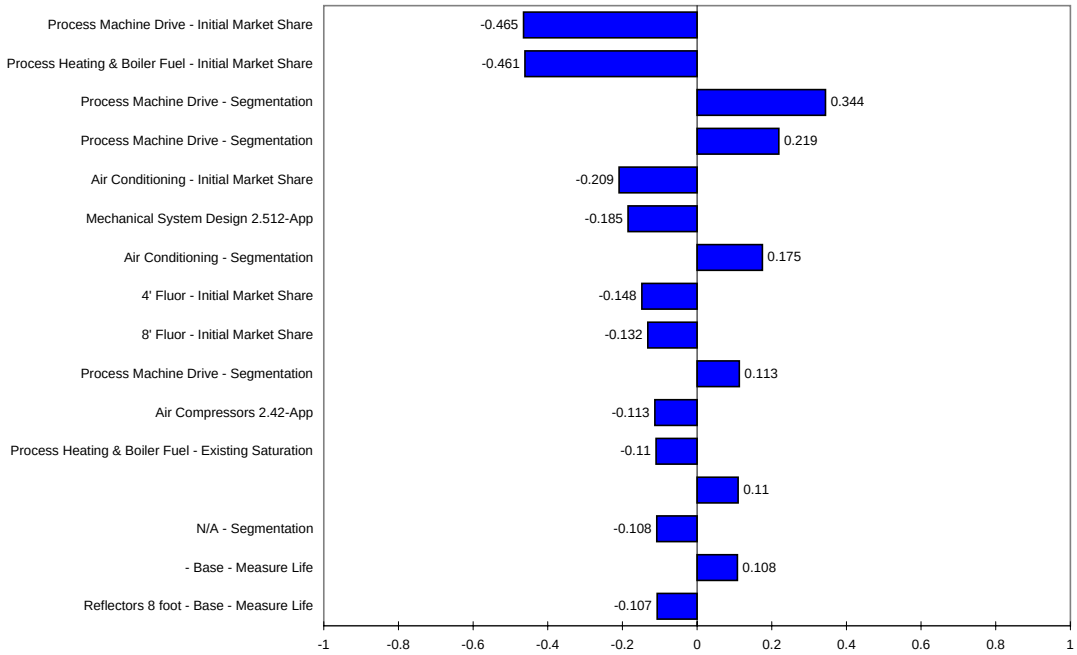

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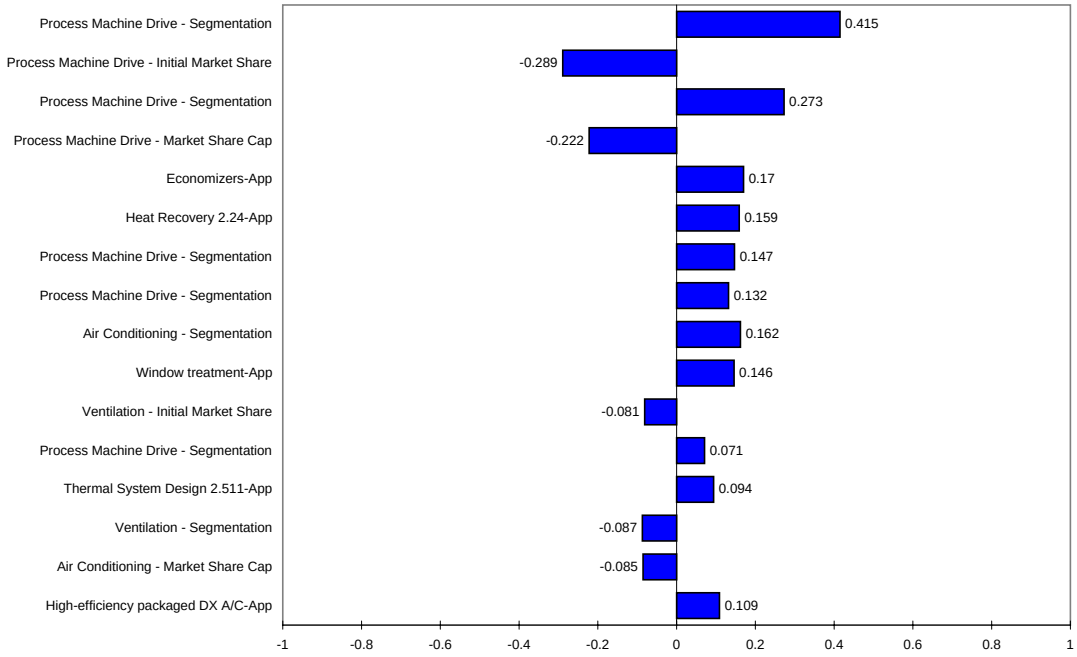

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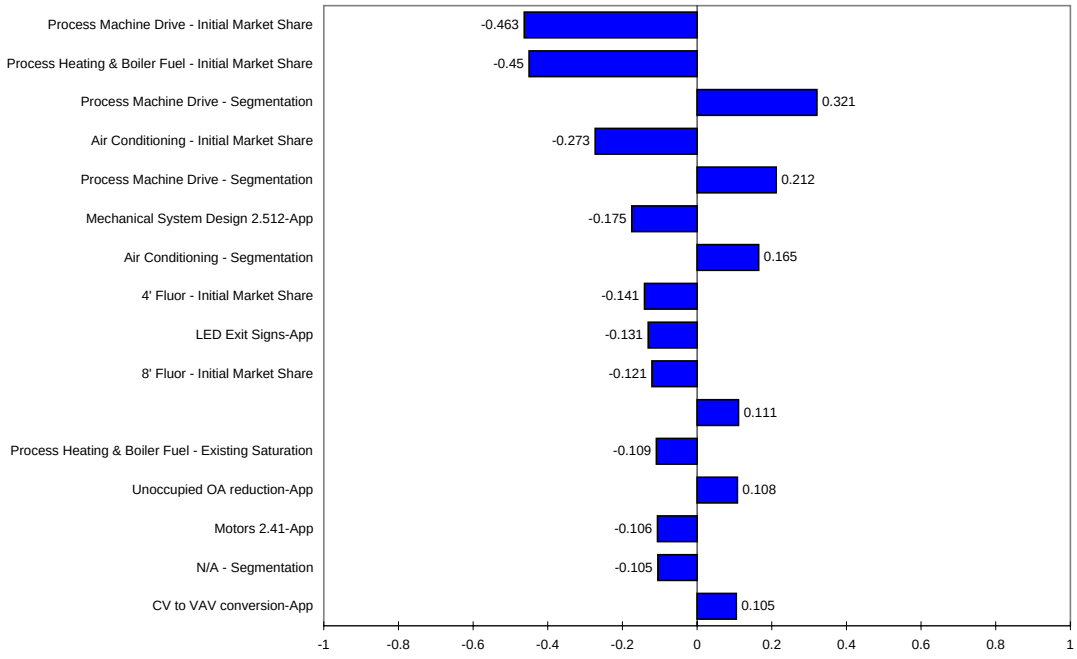

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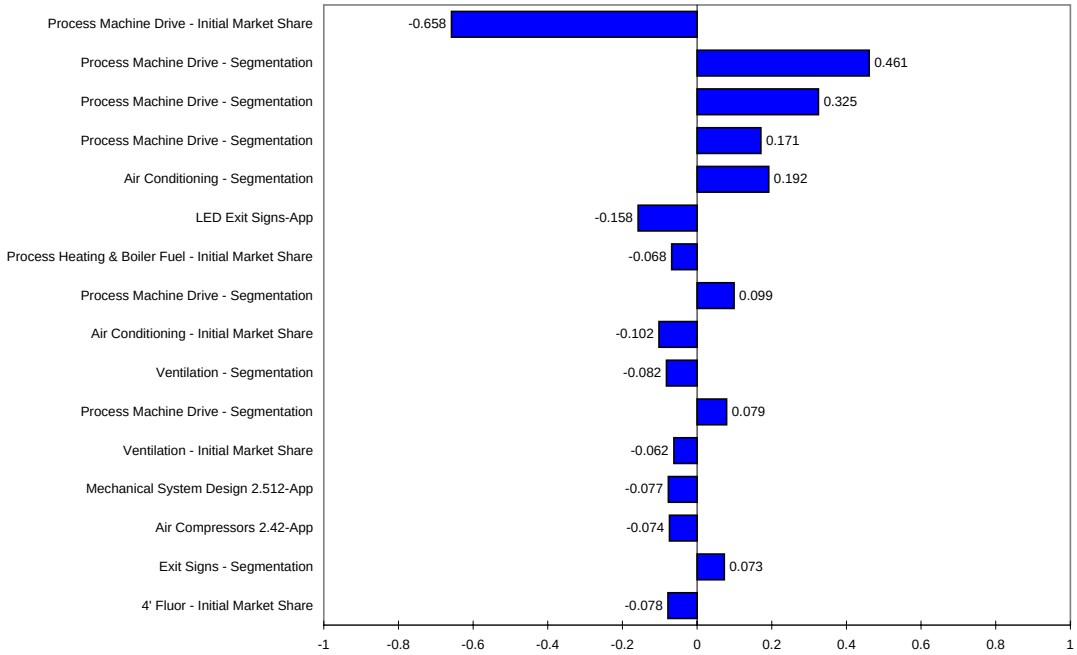

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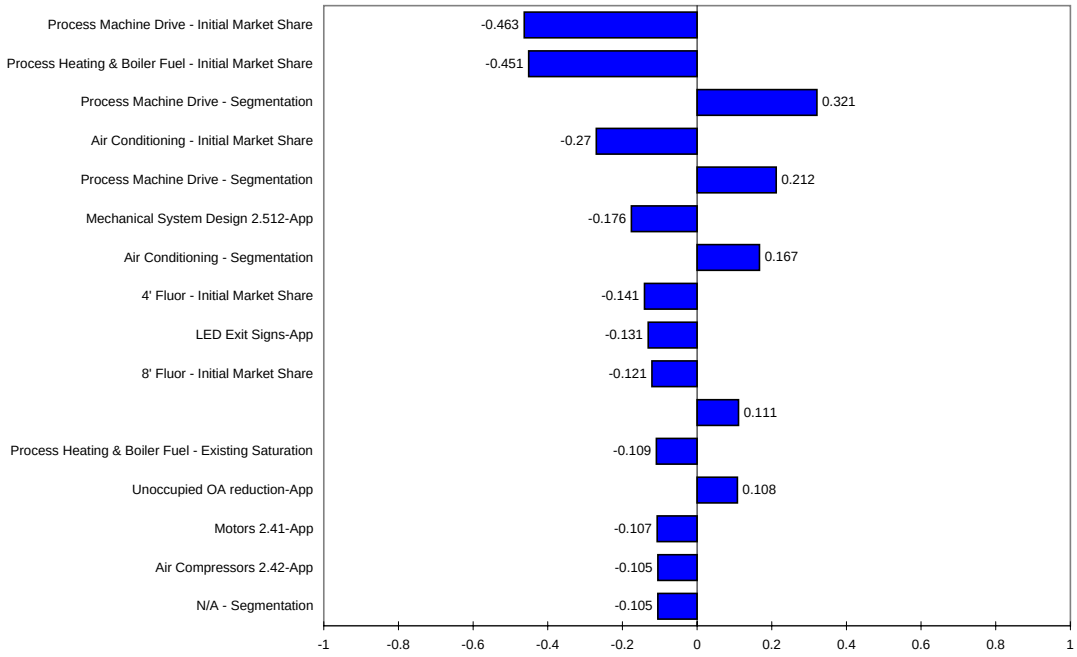

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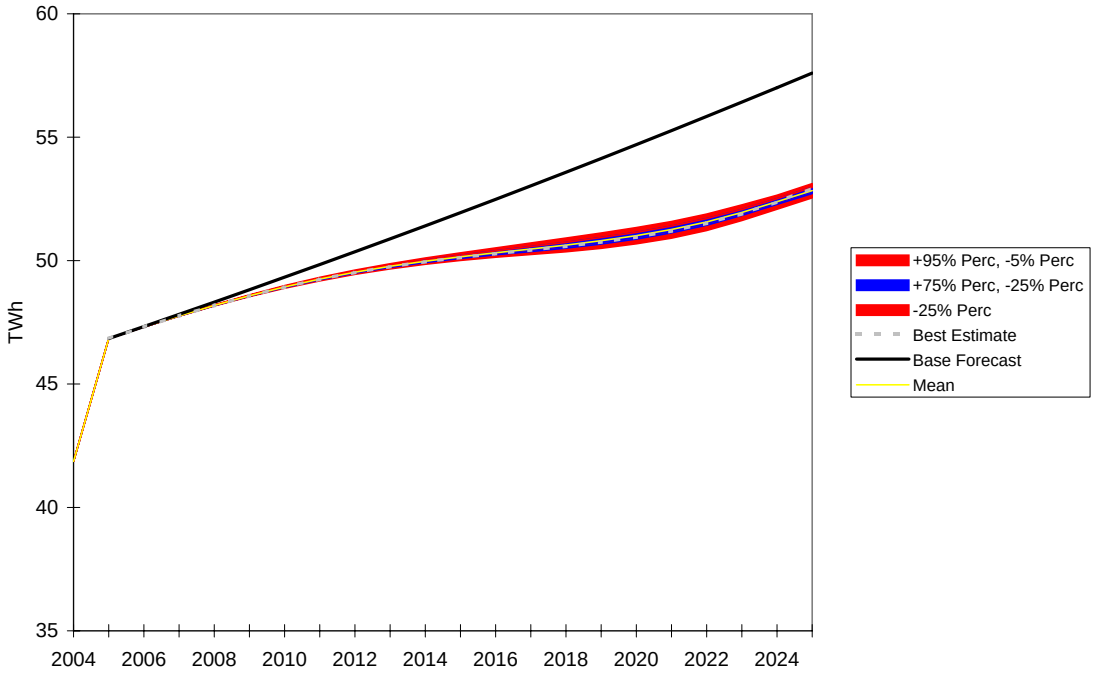

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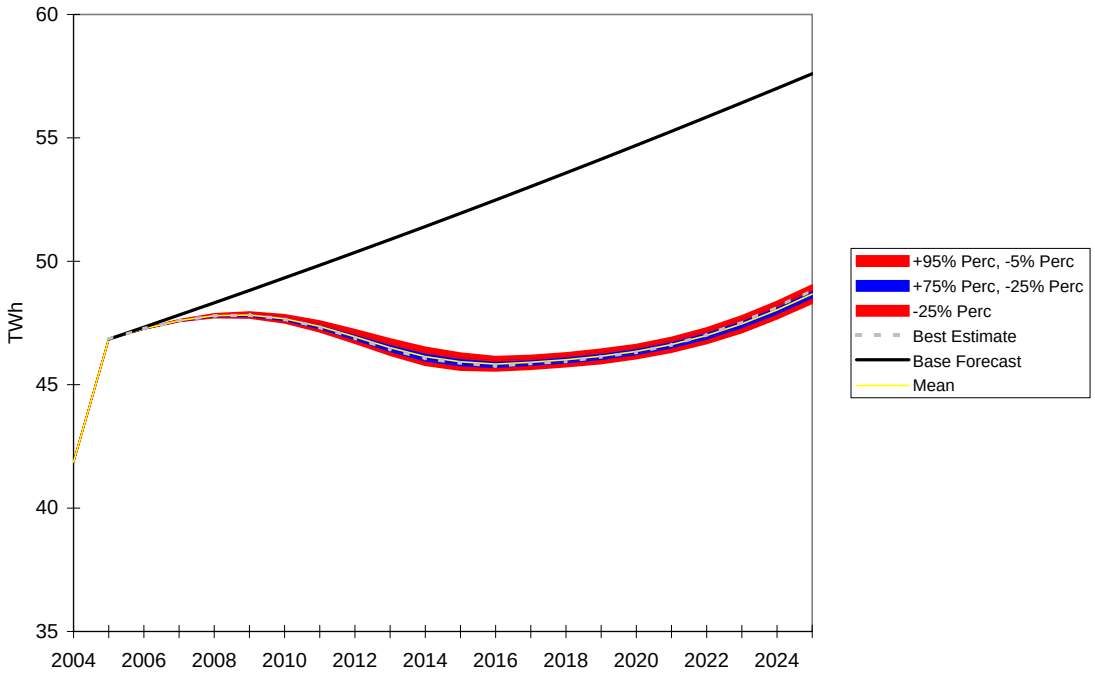

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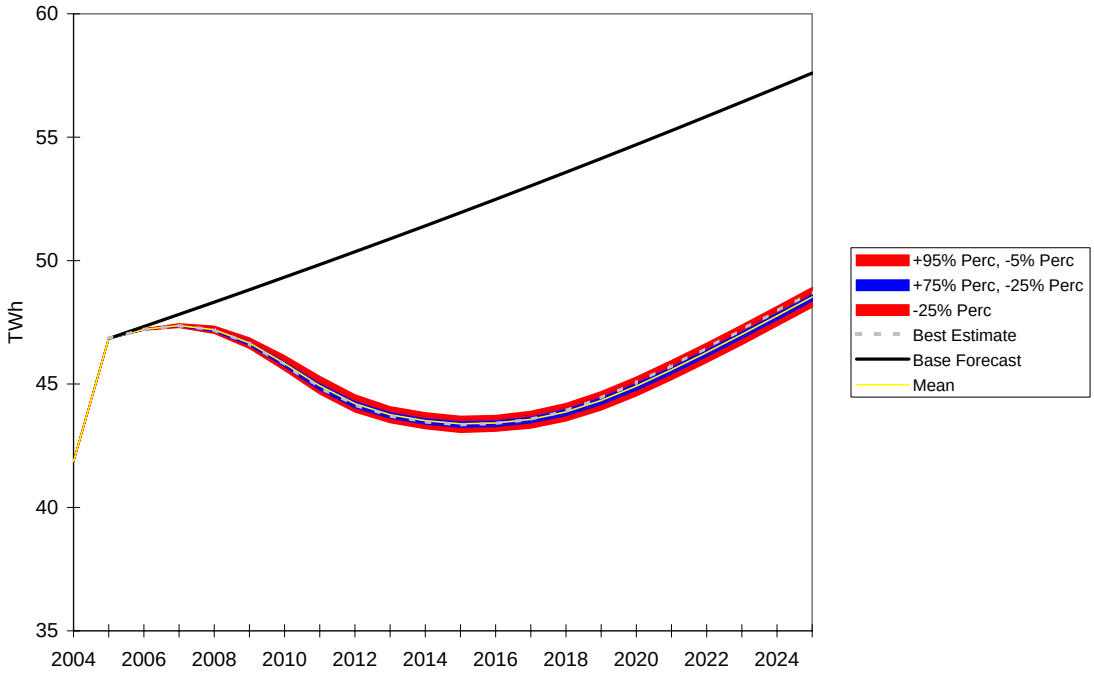
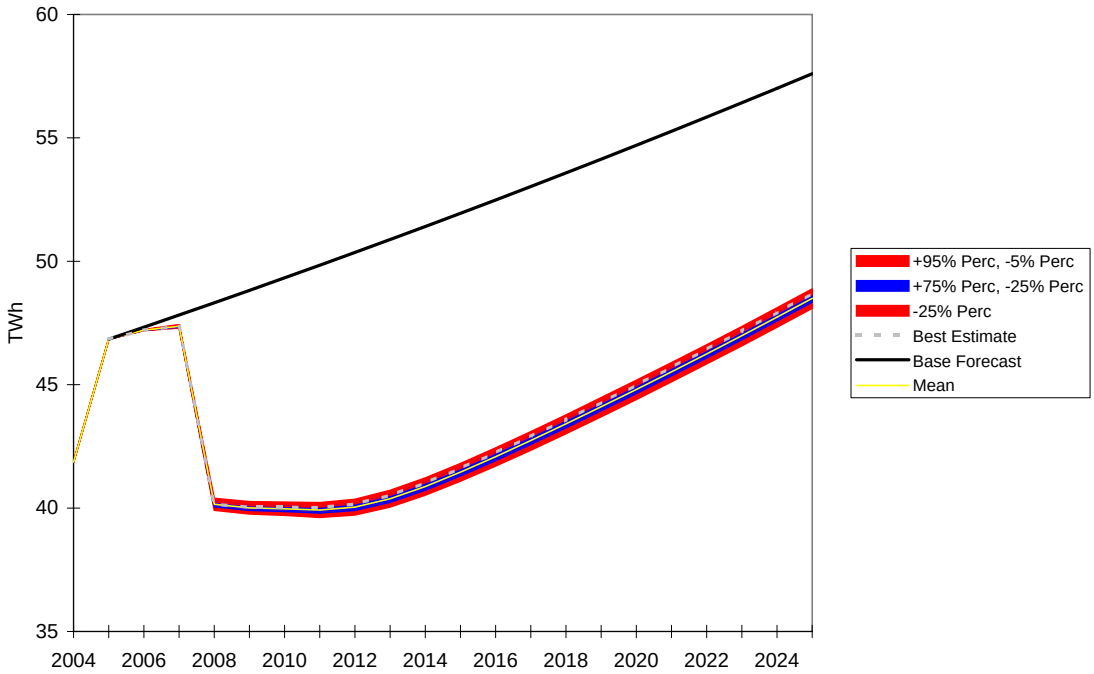
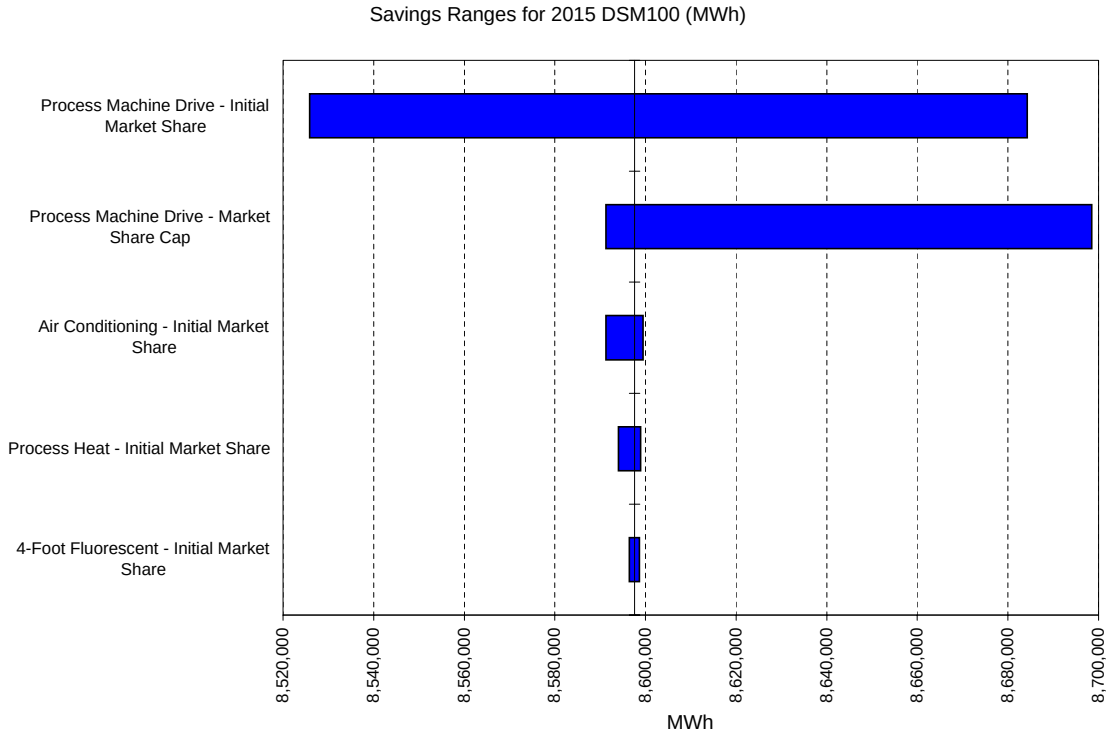
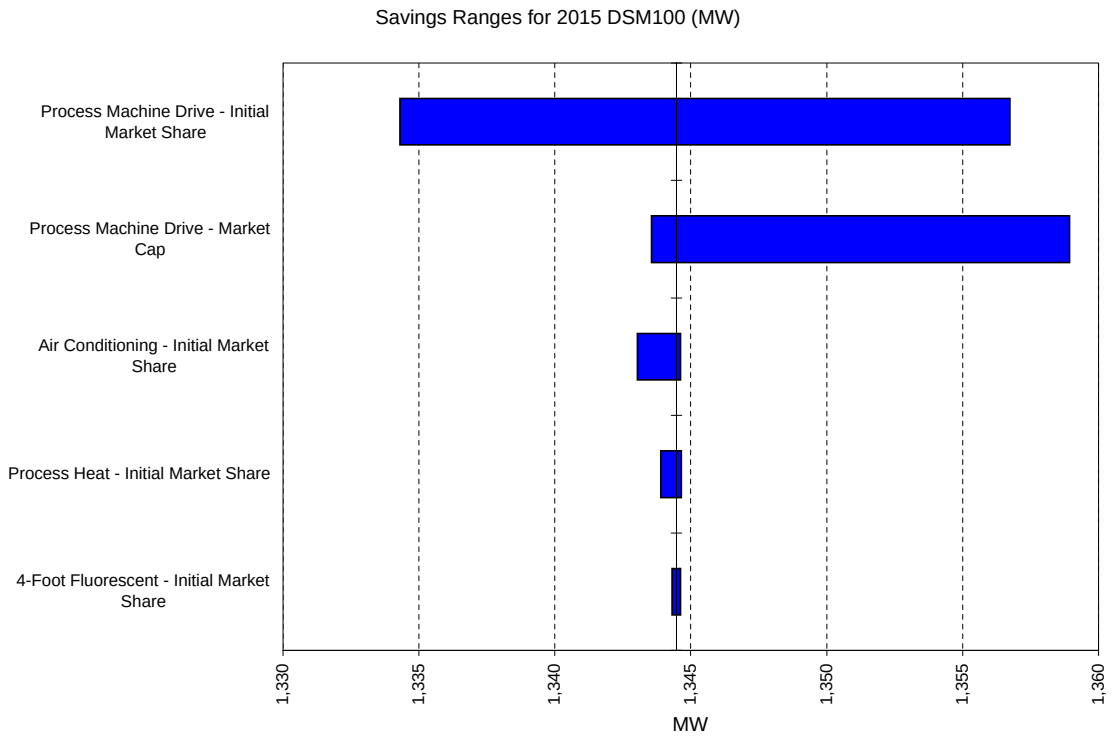


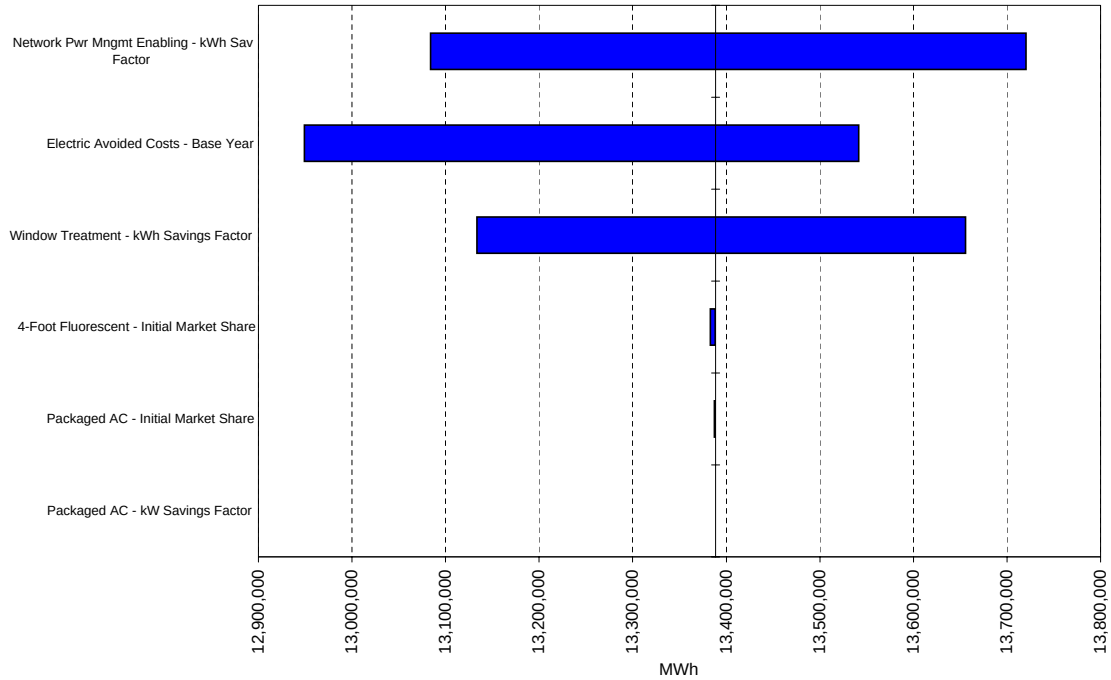
Base Forecast and DSM100 & Stds Uncertainty Band (TWh)




Savings Ranges for 2015 DSM100 (MWh)
Process Machine Drive - Initial Market Share
Process Machine Drive - Market Share Cap
Air Conditioning - Initial Market Share
Process Heat - Initial Market Share
4-Foot Fluorescent - Initial Market Share
8,520,000
8,540,000
8,560,000
8,580,000
8,600,000
8,620,000
8,640,000
8,660,000
8,680,000
8,700,000
MWh


Savings Ranges for 2015 DSM100 (MW)
Process Machine Drive - Initial Market Share
Process Machine Drive - Market Cap
Air Conditioning - Initial Market Share
Process Heat - Initial Market Share
4-Foot Fluorescent - Initial Market Share
1,330
1,335
1,340
1,345
1,350
1,355
1,360
MW

Savings Ranges for 2015 DSM100 (MWh)



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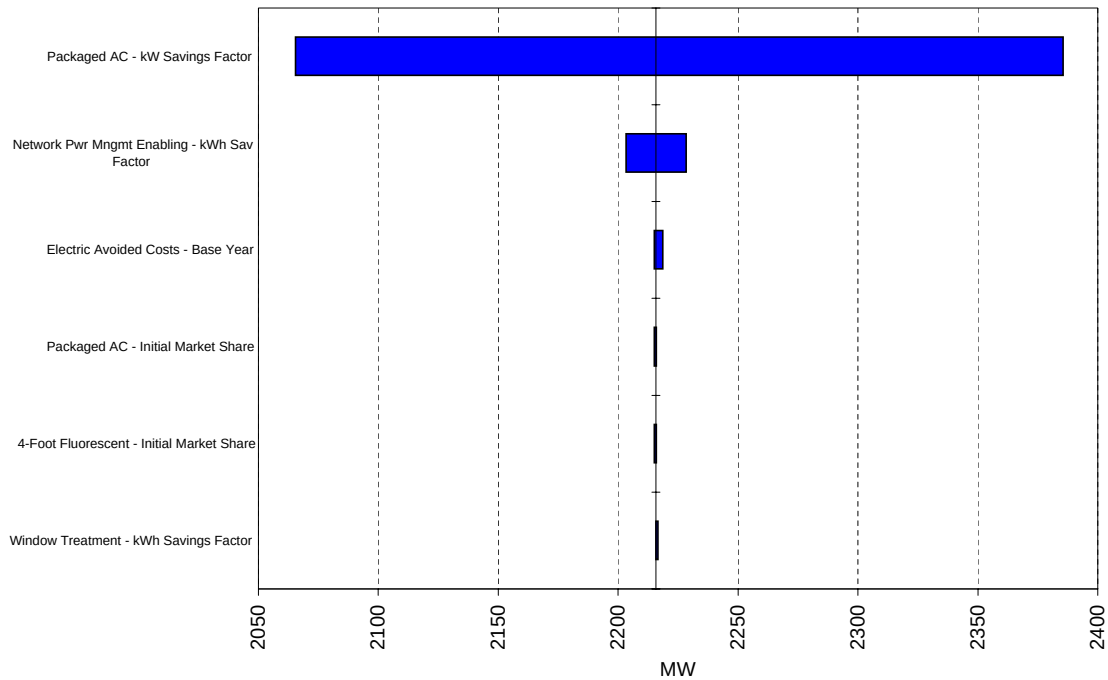

Canadian Energy Research Institute

Electricity Generation Technologies: Performance and Cost Characteristics

Prepared for the Ontario Power Authority

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August 2005

CANADIAN ENERGY RESEARCH INSTITUTE

Relevant • Independent • Objective

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CHAPTER 1
INTRODUCTION

1.1 Background

This report, commissioned by the Ontario Power Authority's (OPA), provides an evaluation of the various supply technologies and resources and associated risks. The data and results of this study will be used as key inputs to assist the Ontario Power Authority in designing an Integrated Power System Plan (IPSP) that balances issues of reliability, the environment and the costs of electricity to the public. Our study provides quantitative information relevant to the issues of reliability and costs.

The task of planning short, medium and long term generation needs is complex; it must consider matters of dispatching, load, demand side management and electricity finance and pricing. Due to the ubiquitous nature of electricity, the average electricity customer (load) generally thinks about electricity in two circumstances; when they experience an outage or pay the electricity bill. The former is an issue of reliability and availability the later an issue of electricity generation cost. The choice of market structure and supply mix will ultimately determine the costs of electricity which one way or another must be born by the consumers- either through higher prices or higher taxes. Here again the ubiquitous nature of electricity makes its long run (levelized) cost one of the most significant prices in the economy. Higher electricity prices not only take a bite out of the consumer's budget but also affect the competitiveness of businesses. A clean environment, an important element of the quality of life, is becoming an increasing priority to Canadians. As a nation we have signed the Kyoto Protocol which requires that we reduce green house gas (GHG) emissions and therefore all provinces will be expected to share some of the burden to meet our international commitments. Planning Ontario's electricity supply mix would be an easy job if a single technology was superior to others in all three areas- the environment, reliability and costs. Unfortunately, no such "silver bullet" technology exists and trade offs will have to be made. From a planning perspective it is desirable to make decisions on the basis of the best information currently available' our report provides current quantitative information relevant to the issues of reliability and costs.

1.2 Objective and Scope and Method

Our report addresses a vital aspect of the planning process; the main objective of this report is to quantify the relative tradeoffs between technologies on the dimensions of performance and costs. Environmental impacts are only discussed on a qualitative basis. The scope of our report includes the following technologies: nuclear, hydro, coal, wind, natural gas, biomass, gasification, solar, fuel cell and photovoltaic. Additionally we provide a discussion on price forecasts for coal and natural gas. With respect to technologies, CERI does not provide analysis, but rather summarizes information retrieved from public sources and discussions with industry. No attempt has been made to verify the data and CERI accepts no liability for errors or inaccuracies in information provided by others. All results are based on information available at the time of

review. NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.

In the body of the text results are reported in the currency and unit found in the original source. A summary table, included with the report, indexes and displays the results of many sources contained within the body of the report. However, the summary table is not exhaustive and users of this report are encouraged to read each section to a gain a complete perspective of the information being provided. In the summary table, results are reported in USD with CERI having made any necessary conversions.

1.3 Organization of the Report

The report is organized as follows:

- Chapter 2 Nuclear Power Plants
- Chapter 3 Hydro Power Plants
- Chapter 4 Wind Power Plants
- Chapter 5 Coal Power Plants
- Chapter 6 Coal and Biomass Gasification
- Chapter 7 Natural Gas Turbine Power Plants
- Chapter 8 Solar & Fuel Cells
- Chapter 9 Natural Gas and Coal Prices
- Chapter 10 Comparative Summary

CHAPTER 2
NUCLEAR POWER PLANTS

2.1 Overview

In recent decades the nuclear power industry has managed to improve the output of existing nuclear power plants quite dramatically. Nuclear reactors produce, contain and control the release of energy from splitting of U235 atoms. In electric power plants, this energy is to heat water to make steam. The steam, in turn, drives the turbine-generators to make electricity. The fissioning of uranium is used as a source of heat in a nuclear power station in the same way that the burning of coal, gas or oil is used as a source of heat in a fossil fuel power plant. Nuclear reactors are essentially large steam engines.

This chapter will provide a brief description of various types of nuclear reactors and a discussion of their performance and costs.

2.2 Nuclear Technologies – Generic Considerations

Several components are common in most types of nuclear reactors: fuel, the control rods, coolant and the moderator. Control rods regulate the chain reaction of the splitting of atoms. The coolant, like a radiator in an automobile, carries away the heat produced by the fission process so that the reactor core does not overheat and produce steam through heat exchange. The moderator controls the speed at which the atoms travel. The slowing down of the atoms actually increases their opportunity to split and, therefore, increases the amount of energy released.

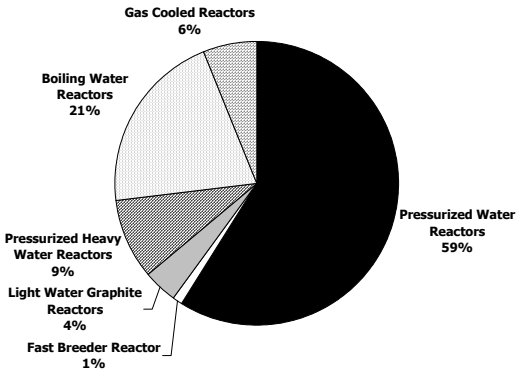
During normal operation, there are no emissions of greenhouse gases or ozone precursors from nuclear power plants, although there are direct and indirect emissions associated with plant construction. There are radioactive emissions from nuclear power plants during normal operations, but the literature suggests that these are actually lower than the corresponding radioactive emissions from coal-fired power plants.

Nuclear Energy Institute notes that the average capacity factor of operating nuclear power plants in the United States in 1980 was 56.3 percent; in 1990, 66 percent; and in 2004, 90.5 percent. Similar improvements have occurred in other countries. Unit operating and maintenance costs in the United States have also fallen over time.

Figure 2.1 portrays the mix of reactor types in use worldwide. In spite of the influx of many complex engineering designs, as demonstrated in Figures 2.2 through 2.5, there are two main nuclear power types: those moderated by light water and those moderated by heavy water (deuterium oxide). Light water reactors are divided further into Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs). They comprise 59 percent and 21 percent, respectively, of reactor types currently used around the world. Atomic Energy of Canada Limited

(AECL) pioneered heavy water technology. CANDU power plants are classified as PHWRs (pressurized heavy water reactors). The CANDU 6, like its predecessors, utilizes heavy water as both moderator and coolant. The ACR-1000, AECL's latest design, utilizes heavy water as moderator but ordinary (light) water as coolant.

Figure 2.1
Reactor Types in Use Worldwide, January 2004



SOURCE: World Nuclear Association

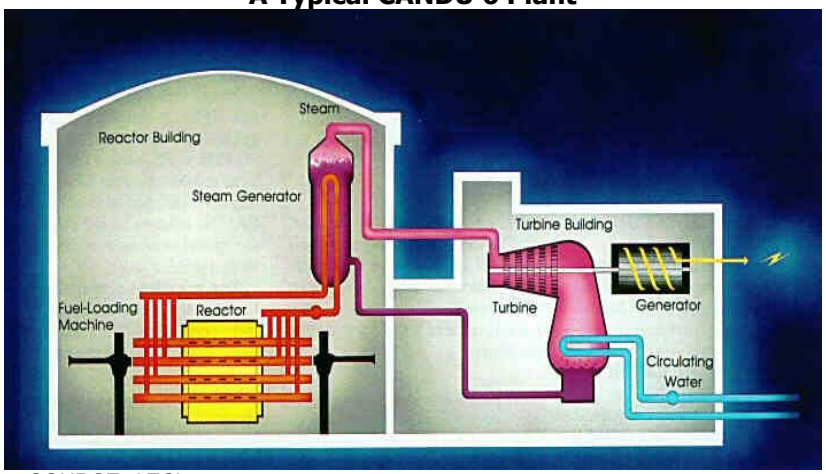
2.3 CANDU 6 Technology

Figure 2.2 is a schematic of CANDU 6 technology. The CANDU 6, like its predecessors, uses natural uranium (0.7 percent U235) as fuel, and in principle can also use spent uranium from PWRs and BWRs. In general terms, this technology has a higher capital cost than light water technology because of the initial cost of heavy water, but a lower fuel cost because no enrichment is required.

2.3.1 Performance Characteristics

Since there are relatively few CANDU 6 units in existence, it is relatively easy to evaluate the performance of each unit, as in Table 2.1. In general terms the lowest capacity factors belong to the units constructed in the 1980s, while the highest ones belong to the newer units. One might be tempted to ascribe this to degradation over time, but this is not borne out by the statistics. In fact, capacity factors for nuclear power plants have been rising world-wide over time**.** (Over the past two decades the United States has been deriving more and more electricity each year from a declining number of operating nuclear power plants.)

Figure 2.2
A Typical CANDU 6 Plant



SOURCE: AECL

Among the older CANDU 6 units only Point Lepreau, which is due for refurbishment, had a lower capacity factor in 2004 than its lifetime average. Stricker and Leclercq[1] report a "capability factor" of 89.6 percent for U.S. nuclear power plants in 2003, remarkably similar to the capacity factor of 89.1 percent for Canada in 2004, as shown in Table 2.1. The Canadian Electricity Association (CEA)[2] compares operational performance of nuclear and other technologies. Over the five-year period 1999-2003 it reports nuclear units in Canada were "available but not operating" only 0.67 per cent of the time - Canadian nuclear plants deliver essentially all they can produce to the grid. In both Canada and the United States, unlike France where nuclear constituted 77 percent of 2003 electricity generation, nuclear is base-loaded with almost no need for dispatchability.

The CEA also reports that over the same five-year period the probability that a unit would be unavailable if needed was 7.5 percent for all nuclear units[3].

2.3.2 Capital and Operating Costs

The chief risks to any projection of levelized costs for nuclear are those of capital cost overruns, rising interest rates and achievable capacity factors. In its decision on an application by New Brunswick Power Corporation to refurbish the Point Lepreau nuclear power plant, the New Brunswick Board of Commissioners of Public Utilities stated, "Nuclear fuel is a low cost fuel and represents less than 15 percent of the operation, maintenance and administration costs of operating Point Lepreau."[4]

1 Stricker, L. and J. Leclercq, "An Ocean Apart", Nuclear Engineering International, December 2004, pp. 20-26.

2 Canadian Electricity Association, 2003 Generation Equipment Status Annual Report.

3 By way of comparison, the DAUFOPs of other technologies were 9.20 percent for combustion turbines, 13.39 percent for gas-fired steam turbines, 6.95 percent for oil-fired steam turbines and 9.38 percent for coal-fired steam turbines.

4 Page 13 of the Board's 2003 decision.

Table 2.1
CANDU 6 Capacity Factors

Name of Unit	Capacity MW	In-Service Year	Capacity Factor (%) 2004	Capacity Factor (%) Lifetime
Pt. Lepreau (New Brunswick)	680	1983	77.5	82.7
Wolsong 1 (Korea)	679	1983	90.3	86.0
Gentilly 2 (Quebec)	675	1983	87.8	79.3
Embalse (Argentina)	648	1984	86.1	84.8
Cernavoda 1 (Romania)	706	1996	89.7	86.8
Wolsong 2 (Korea)	700	1997	92.6	92.6
Wolsong 3 (Korea)	700	1998	96.4	93.9
Wolsong 4 (Korea)	700	1999	97.4	96.4
Qinshan 4 (China)	700	2002	77.3	84.2
Qinshan 5 (China)	700	2003	94.0	87.8
Simple Average	**689**		**89.1**	**87.4**

SOURCE: Canadian Nuclear Association.

Because the costs of nuclear are highly predictable (and largely sunk) once placed in service, the minimization of financial risks requires that revenues be similarly predictable. Obtaining capital at a reasonable cost is particularly important for nuclear because it is so capital-intensive. Such capital is unlikely to be forthcoming on favourable terms if the output will be subject to the price volatility characteristic of wholesale power markets. Stable pricing for at least part of a supply portfolio may also be in the interests of distribution utilities and their customers.

A CERI study[5] based on information provided by AECL reported the following cost information in year 2003 Canadian dollars for the CANDU 6 with an operating life of 30 years. Allocation of construction cost by year: Year 1, 8.0 percent; Year 2, 21.0 percent; Year 3, 27.1 percent; Year 4, 19.6 percent; Year 5, 12.0 percent; Year 6, 7.2; Year 7 (first operating year) 5.1 percent.

5 Canadian Energy Research Institute, "LUEC Comparison of Alternate Technologies for Baseload Generation in Ontario," August 2004.

Table 2.2
Levelized Cost of Nuclear Electricity Generation – CANDU 6 (2003 CDN $)

Overnight Construction Cost (2 x 673 MW net)	$4.0 billion or $2,972/kW	
Fuel Cost	$2.30/MWh	
Spent Fuel Cost	$1.45/MWh	
	Public Basis	Merchant Basis
Discount Rate	5%	8%
Decommissioning Cost per Year of Operation	$1.16/MWh	$1.17/MWh
Non-Fuel Operating & Maintenance Cost	$14.95/MWh	$15.08/MWh
Levelized Capital Cost	$43.58/MWh	$57.17/MWh
Levelized Income Tax	0	$11.47/MWh
Total Levelized Cost	$63.44/MWh	$88.64/MWh

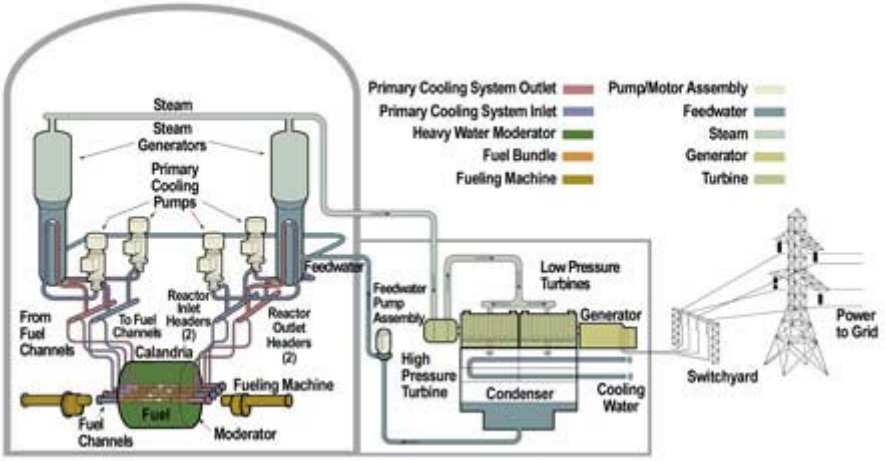
SOURCE: Canadian Energy Research Institute, "Levelized Unit Electricity Cost Comparison of Alternative Technologies for Baseload Generation in Ontario", August 2004, Table 3.1.
NOTE: Construction time is 6 years prior to generation.

2.4 ACR (Advanced CANDU Reactor) Technology

Much like its predecessors, the ACR has retained the following features: horizontal fuel channels, fuel bundle design, low-pressure heavy water moderator, high neutron efficiency and on-power fueling. However, the ACR, depicted in Figure 2.3, has also incorporated features from PWR technology. The most important similarity is the ACR's adoption of light water as a coolant.

The ACR, like the CANDU 6, uses horizontal pressure tubes. Several hundred horizontal pressure tubes submerge the moderator. Due to the horizontal pressure tube design, the reactor can be refueled on-line. A reactor employing PWR technology needs to be shut down while refueling occurs. A PWR refueling outage can last up to two months. One of the unique traits of the ACR is the simple short fuel bundles compared to the full-length fuel string design for PWRs.

Figure 2.3
Diagram of an ACR Plant



SOURCE: AECL website, www.aecltechnologies.com/Content/ACR/Plant_Flow.htm

2.4.1 Performance Characteristics

AECL has found the ACR to be physically smaller and more efficient – in terms of capacity and cost – than the CANDU 6. The reactor now uses low-enriched uranium (1.5-2.1 percent U235), rather than natural uranium that fueled its forerunner. ACR technology employs heavy water as moderator but light (ordinary) water as coolant. The 2.1 percent level of enrichment would be achieved by a combination of natural uranium (0.7 percent U235) and enriched uranium (3 percent to 4 percent U235).

Since there are no ACRs in commercial operation, there is no track record of performance data. AECL expects that an ACR, like a PWR of recent design, will achieve a 93 percent capacity factor over its lifetime. Stricker and Leclercq[6] note that "the stated U.S. goal is a load factor of 93 percent."

2.4.2 Capital and Operating Costs

The aforementioned 2004 CERI study analyzed ACR-700 rather than ACR-1000 costs. Its findings for the ACR-700 were as follows:

6 Stricker, L. and J. Leclercq, "An Ocean Apart", Nuclear Engineering International, December 2004, p. 21.

Table 2.3
Levelized Cost of Nuclear Electricity Generation – ACR 700 (2003 CDN $)

Overnight Construction Cost (2 x 703 MW net)	$3.3 billion or $2,347/kW	
Fuel Cost (including spent fuel)	$5.45/MWh	
Decommissioning Cost per Year of Operation	$11.8 million or $0.76/MWh	
	Public Basis	Merchant Basis
Discount Rate	5%	8%
Non-Fuel Operating & Maintenance Cost	$12.57/MWh	$12.68/MWh
Levelized Capital Cost	34.58/MWh	$45.31/MWh
Levelized Income Tax	0	$9.13/MWh
Total Levelized Cost	$53.36/MWh	$73.33/MWh

SOURCE: Canadian Energy Research Institute, "Levelized Unit Electricity Cost Comparison of Alternative Technologies for Baseload Generation in Ontario", August 2004, Table 3.1.
NOTE: Service life is 3 years and construction time is 6 years prior to generation.

Allocation of construction cost by year: Year 1, 8.0 percent; Year 2, 21.0 percent; Year 3, 27.1 percent; Year 4, 19.6 percent; Year 5, 12.0 percent; Year 6, 7.2; Year 7 (first operating year) 5.1 percent.

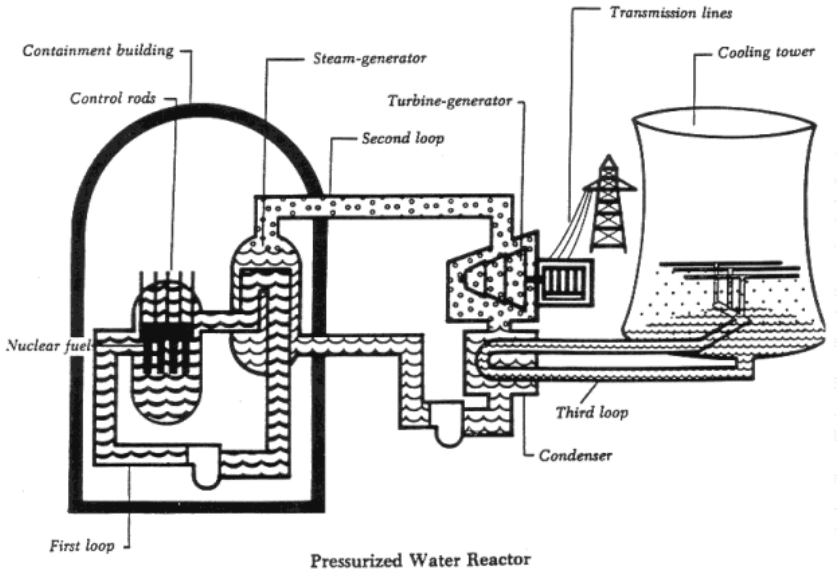
More recently, AECL provided CERI with a range of cost estimates in 2004 Canadian dollars for the ACR-1000, with twin 1121 MW (net) units operating at a 93 percent capacity factor. Its overnight capital cost would be $3.6 to $4.2 billion. It would have a fuel cost of $92 million per year and a non-fuel operating cost of $144 million.

2.5 Pressurized and Boiling Water Reactor Technology

The PWR (pressurized water reactor) is the most common type of nuclear reactor in the world. All nuclear reactors in France employ PWR technology except for one fast breeder. According the WNA there are 265 PWRs worldwide, with 69 PWRs in use for power generation in the US alone. In fact, virtually all power reactors in the US are either PWRs or BWRs.

In the BWR, the water heated by the reactor core turns directly into steam in the reactor vessel as it is allowed to boil. It is then used to power the turbine-generator. In a PWR, the water passing through the reactor core is kept under pressure so that it does not turn to steam at all – it remains liquid. The PWR is distinguished by having a primary cooling circuit and a secondary circuit. The former allows the pressurized water to be circulated in a closed system of pipes. In the process the heat from this circuit heats up the secondary circuit. Because the secondary circuit has less pressure, the water within it is permitted to boil and the steam powers the turbine. The design of the PWR is depicted in Figure 2.4.

Figure 2.4
Diagram of a PWR Plant



SOURCE: National Research Council website,
www.nrc.gov/reading-rm/basic-ref/teachers/pwr-schematic.html

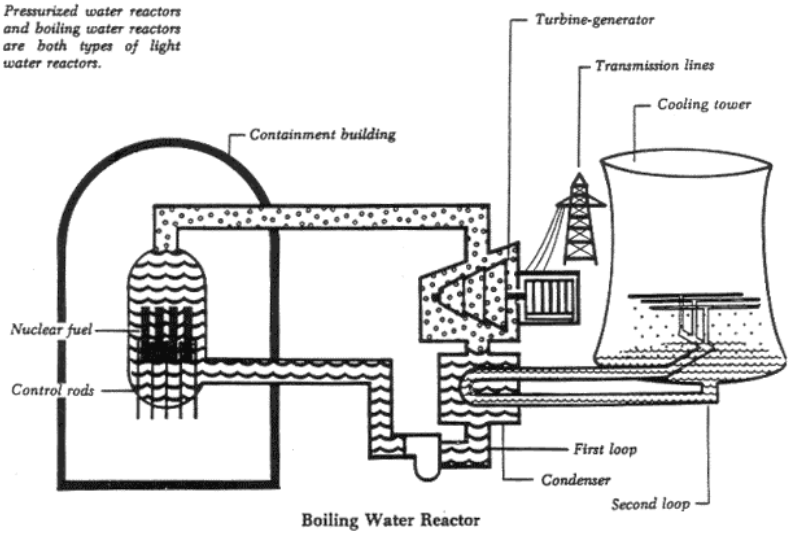
The PWR and BWR use enriched uranium (4-5 percent U235), rather than low-enriched uranium that fuels the ACR. In addition, while ACR technology employs heavy water as moderator and light (ordinary) water as coolant, the PWR uses ordinary water as both coolant and moderator.

Other technological differences include the use of a pressure vessel instead of the ACR's horizontal pressure tubes. The former cannot, however, be refueled on-line. Reactor employing PWR technology needs to be shut down while refueling occurs. Refueling outages can last up to two months with some reactors, approximately every between 18 and 24 months.

The enriched uranium is fabricated into long zirconium-alloy tubes. While the ACR has simple short fuel bundles, PWR technology uses a full-length fuel string design.

In a typical boiling water reactor (BWR) the reactor core creates heat and a single loop both delivers steam to the turbine and returns water to the reactor core to cool it, as in Figure 2.5. The cooling water is force-circulated by electrically powered pumps. It is piped directly to the turbine. The turbine spins, driving the electric generator, producing electricity. Emergency cooling water is supplied by other pumps, which can be powered by onsite diesel generators. Other safety systems, such as the containment building air coolers, also need electric power. BWRs are manufactured by General Electric.

Figure 2.5
Diagram of a BWR Plant



SOURCE: National Research Council website,
www.nrc.gov/reading-rm/basic- ref/teachers/bwr-schematic.html

2.5.1 Performance Characteristics

Costs and performance for BWR are essentially the same as for PWR technology. Moreover, as Stricker and Leclercq[7] advise, "Analysis of the relative performance of these two types of reactor shows that, for a number of years, BWR and PWR performance has been equivalent, which justifies an overall approach to the fleet and tends to show that improved performance now depends more on management than design."

2.5.2 Capital and Operating Costs

Throughout this and other studies, capital and operating costs in countries other than the United States have been converted to U.S. dollars using historical exchange rates. This procedure, while objective, does not take into account the differences in wage rates, productivity and climate-related design differences between countries. Based on conversations with a cost engineer, it would appear that the cost of building a nuclear power plant in Canada could be 14 per cent higher than would be estimated using average costs for the United States and converting them into Canadian dollars at prevailing exchange rates.

The overnight construction cost of a third-generation, 1000 MW nuclear power plant is reported by the OECD[8] as US$1,894 billion, or US$1,894/kW. Levelized investment cost works out to be $17.00/MWh at a 5 percent discount rate, or $33.40 at a 10 percent discount rate. Under either

7 Stricker, L. and J. Leclercq, "An Ocean Apart", Nuclear Engineering International, December 2004, p. 20.

8 OECD: Projected Costs of Generating Electricity: 2005 Updates.

discount rate the levelized O&M cost works out to be $8.50/MWh and nuclear fuel comes to about $4.65/MWh.

The OECD study cited above applied field surveys and covered a multitude of electricity generating technologies in a few countries including Canada and the USA to calculate the levelized cost of electricity generation. It applied generic assumptions in order to derive its calculations. Salient assumptions include: economic lifetime of 40 years, average load factor for base-load plants of 85 percent and discount rates of 5 percent and 10 percent; the base year is July 2003. The electricity generation costs are busbar costs as previously defined. Table 2.2 shows the levelized cost of electricity generation for nuclear plants by category.

Table 2.4
Levelized Cost of Nuclear Electricity Generation – PHWR (2003 USD/MWh)

Country: Plant Type	Discount Rate	Net Capacity MW	Overnight Construction Cost '000 US$	Levelized Capital Cost	Levelized O&M Cost	Levelized Fuel Cost	Levelized Electricity Cost
Canada: PHWR/OT	5%	1406	1931	13.5	8.9	3.6	26
Canada: PHWR/OT	10%	1406	1931	24.6	8.9	3.6	37.1
USA: GENIII/OT	5%	1000	1894	17	8.5	4.6	30.1
USA: GENIII/OT	10%	1000	1894	33.4	8.5	4.7	46.5

SOURCE: OECD (NEA/IEA), Projected Cost of Generating Electricity 2005 Update, Paris, France.

Note: OT= Once-through fuel cycle

The United States Energy Information Administration has also published selected information, shown in Table 2.5 below, for "Advanced Nuclear", a generic costing of the PWR and BWR technologies employed in the United States.

Table 2.5
Cost of "Advanced Nuclear" in USA (2003 USD)

Technology	Advanced Nuclear
Capacity (MW)	1000
Heat rate (Btu/kWh)	10,400
Overnight Cost[1] (2003 $/kW)	1,975
Variable O&M (2003 mills[2]/kWh)	0.44
Fixed O&M (2003 $/KW)	60.06
Lead times (Years)	6

SOURCE: Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38.

CHAPTER 3
HYDRO POWER PLANTS

3.1 Overview

Hydroelectricity is the most important source of renewable energy in Canada, accounting for about 11 percent of total primary energy and over 60 percent of electricity generation.

In 2003, hydroelectricity also contributed approximately 60 percent of Canada's net electricity exports of 6.6 TWh (Manitoba Wildlands, 2004).

This chapter provides a brief description of technical specifications, performance characteristics and associated costs of hydro power electricity generation.

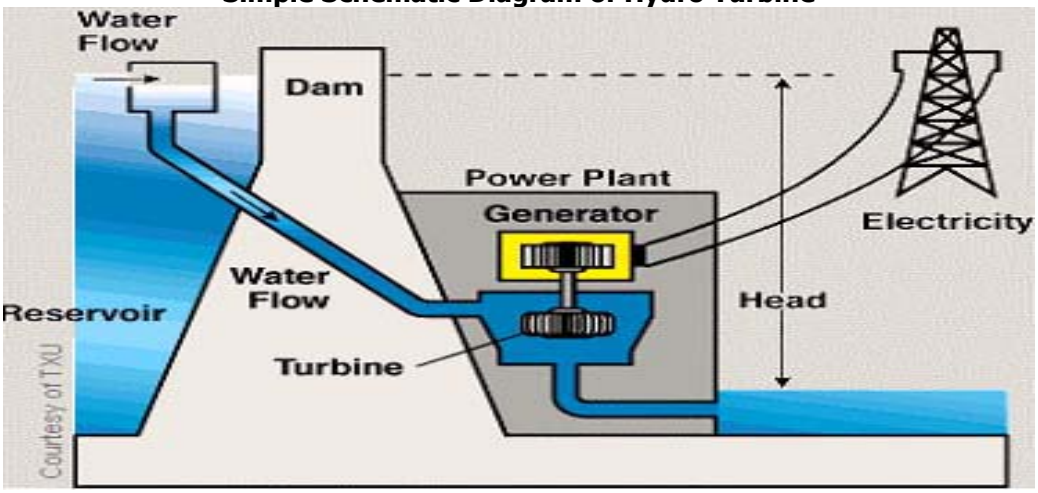
3.2 Hydro Power

Hydroelectricity is generated by the force of water as it falls into turbines and rotates the shaft thereby converting the potential energy of the water into kinetic energy (energy in the form of motion). The amount of energy available depends on the height of the waterfall and the volume of water passing over the fall. Hydroelectric generating plants can "store" energy and then release water to generate electricity when it is needed. This ability to store energy is an asset that can be combined with other renewable technologies like wind energy to enable larger scale use of renewable energy[9]

Today's hydropower plants range in size from small, local projects producing a few kilowatts to huge dams and reservoirs that generate 10,000 MW. Hydroelectric power plants that generate up to 100 kW of electricity are called "micro hydro. Hydro plants that generate more than 100 KW up to 30 MW are called "small hydropower".

9 US Department of Energy: http://www.energy.gov/engine/content.do.

Figure 3.1
Simple Schematic Diagram of Hydro Turbine



SOURCE: http://www.uaf.edu/energyin/webpage/pages/renewable_energy_tech/hydro.htm

3.3 Pumped Hydro

Although most hydropower installations utilize conventional storage in upstream reservoirs, there is increased use of pumped storage in order to capture unused electricity during times of low use. In this mode, water is pumped through a reversible turbine, from a lower reservoir to an upper reservoir during off-peak hours when electricity costs are lowest. Then the water flow is reversed during times of high electrical demand to produce electricity. Water is generally pumped back to the upper reservoir at night and on weekends[10]. While a net energy consumer, pumped storage benefits the utility by increasing the load factor and reducing the cycling of its base load units[11].

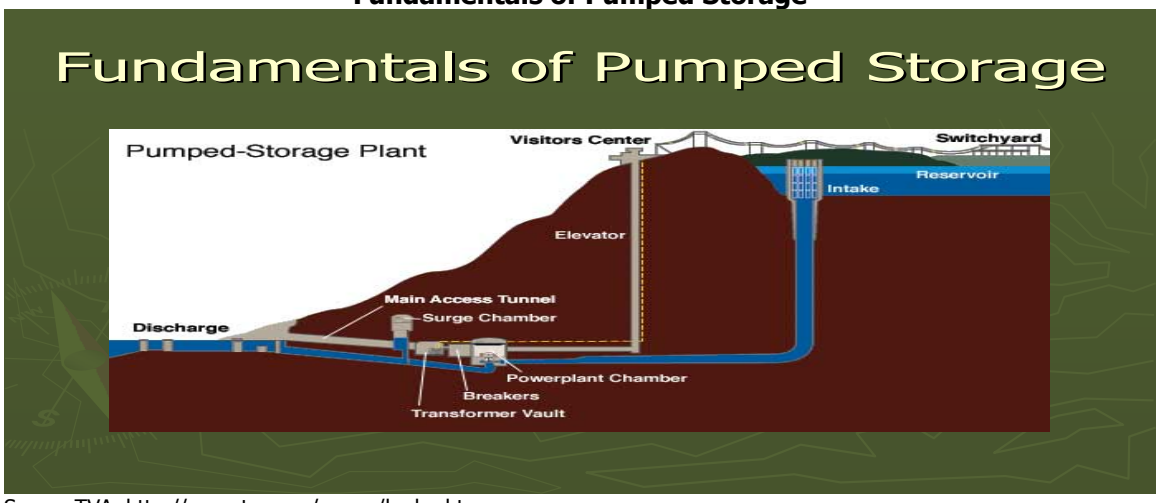
Pumped hydro is available at almost any scale with discharge times ranging from several hours to a few days. Their efficiency is in the 70 percent to 85 percent range. Pumped storage plants are characterized by long construction times and high capital expenditure[12].

10 https://www.dukepower.com/community/learningcenter/generating/pumpedstorage/

11 USDOE: Hydropower Program.

12 http://www.electricitystorage.org/tech/technologies_technologies_pumpedhydro.htm

Figure 3.2
Fundamentals of Pumped Storage



Source TVA, http://www.tva.gov/power/hydro.htm

3.4 Performance Characteristics

Hydroelectric plants represent mature technology whose generation efficiency has not changed significantly over time. As a result, hydro power plants built in 2003 may not be much more efficient than one built in 1983. The same cannot be said however for emerging technologies such as solar thermal generation where technological changes have been rapid.

The efficiency rate of hydroelectricity plants is generally two times greater then fossil fuel plants**.** Hydropower stations have a long life and many existing stations have been in operation for more than half a century and are still operating efficiently [13]

Generating electricity from hydro sources is cheaper than other technologies because there is no fuel cost. Moreover, hydroelectric plants have low maintenance costs, and do not need many workers to run them. On the downside however, the output of hydro power plants depend on water availability which implies that during drought periods, less electricity will be produced.

Hydro power is a reliable source for the generation of electricity. However, it encounters uncertainties that arise from weather, seasonal variations, and contingencies such as outages.

Hydro power stations have the ability to respond within short periods to changes in load demand. This flexibility characteristic enhances their value to the supply mix and to the diverse needs of different consumer classes in general.

An important advantage of hydropower is that it has essentially no atmospheric emissions, such as greenhouse gases, other than water evaporation. This notwithstanding, hydroelectric power can have other kinds of negative environmental effects. Specifically, hydroelectric power

13 http:www.canren.gc.ca

generation may lower the water tables, thereby adversely affecting agriculture. Dams change the stream water quality by altering water temperatures and the level of dissolved gases, thereby interrupting the ecology of the natural river system and damaging vegetation, fish, and other wildlife.

The Canadian Electricity Association (CEA)[14] keeps operating statistics on electricity generating units operated in Canada by electric utilities and by Alcan Primary Metal Group. These statistics permit a comparison of reliability and chosen mode of operation (base load, intermediate, peaking) among the different technologies and fuels.

Table 3.1 shows the values of key operating statistics for hydro technology/fuel in 2003, and their average for the period 1999-2003. The definition of operating factor (OP factor), available but not operating factor (ABNOF), forced outage rate (FOR), and derating adjusted forced outage probability (DAUFOP) are as follows.

- **Operating Factor or OP FACTOR (%)**: Total Operating Time (whether under normal operation, under forced derating or under scheduled derating) divided by Unit Hours, the total number of hours in a year [8760 except in a leap year].

- **Available but not Operating Factor or ABNOF (%)**: 100 percent times (number of hours available for normal operation but not operating plus number of hours available but not operating under forced derating [typically due to a component failure] plus number of hours available but not operating during scheduled deratings), all divided by Unit Hours as defined above.

- **Forced Outage Rate or FOR (%)**: 100 percent times the ratio of Total Forced Outage Time to (Forced Outage Time + Total Operating Time as defined above). Total Forced Outage Time is the sum of hours in a forced outage state, hours in a forced extension of a maintenance outage and hours in a forced extension of a planned outage.

- **Derating Adjusted Forced Outage Probability or DAUFOP (%**): The probability that a generating unit will not be available when required (derating included).

The values of "OP FACTOR" and "ABNOF" reflect the degree of utilization of the units, whereas the values of "FOR" and "DAUFOP" are measures of reliability.

14 Canadian Electricity Association, 2003 Annual Report, Equipment Reliability Information System.

Table 3.1
Operating Characteristics of Canadian Hydraulic Plants

Period	OP FACTOR	ABNOF	FOR	DAUFOP
2003	69.82%	21.62%	1.87%	1.59%
1999-2003	72.46%	18.97%	1.93%	1.70%

SOURCE: Canadian Electricity Association, 2003 Generation Equipment Status Annual Report, Tables 6.1.1 & .2.

Over the five-year period 1999-2003 hydraulic units in Canada were "available but not operating" 18.97 per cent of the time. The CEA also reports that over the same five-year period the probability that a unit would be unavailable if needed ("DAUFOP") was 1.7 percent for all hydraulic units.

3.5 Capital and Operating Costs

The economies of scale favor large power projects over small ones as capital costs per KWh generally decrease with increasing scale. However, the combination of a long lead time, uncertain growth in demand for electricity and price, and uncertainty in the total cost of financing construction increase risks for larger projects. Furthermore, very large projects that must effectively be built as a single large plant (e.g. a very large hydro dam) are more vulnerable to this type of risk than projects for which development can be phased in as several smaller power plants in response to market conditions.

Four comparative cost estimates are discussed here. The first is Electricity Market Model (EMM) of the U.S. Department of Energy. The EMM has cost estimates for building plants in a typical US region. Because hydro cost and performance characteristics are specific for each site, the data represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located. Table 3.2 shows the breakdown of the electricity market model (EMM).

Table 3.2
Cost and Performance Characteristics of Hydro Electricity Generation
(2003 USD)

Size (MW)	Construction time (years)	Overnight cost $/kW	Fixed O&M $/kW	Variable O&M c/kWh	Heat rate Btu/kWe
500	4	1451	12.35	0.46	10338

SOURCE: United States Department of Energy, (2005) Assumptions to the Annual Energy Outlook: the Electricity Market Model (EMM).

The second set of cost estimates is derived from an IEA[15] study which compared costs of hydroelectricity generation for small and large dams in six countries. According to the IEA study, depending on various plant types and capacity levels, overnight hydro construction cost ranged between 1541 USD/kWh in Germany and 6985 USD/kWh in Japan. The expense schedules

15 International Energy Agency, IEA (2005): Projected Costs of Generating Electricity 2005 Update, OECD, Paris.

reported for hydro power plants correspond to construction periods ranging from 1 to 5 years but in most cases most of the expenses are incurred in less than 3 years.

The hydro power plants considered in the IEA study are small or very small units, except the dam in Greece (GRC-H2) which has a total capacity of some 120 MWe. The very high specific construction costs reported for most of the hydro power plants considered in the study likely result from their sizes, although in Austria the specific construction costs reported are lower for the smaller unit. The economic lifetimes of hydro power plants in the study vary from 30 to 60 years. The levelized construction and O&M costs of the IEA study are shown in Table (3.3).

Table 3.3
Levelized Generation Costs of Hydro Power in Selected Countries
(2003 USD/MWh)

	Australia	Australia	Czech	Ger.	Greece	Greece	Slovak	Japan
Plant type	ROR *	Small	Small	Small	ROR*	Dam	ROR*	ROR*
Capacity**	14	1.5	3	0.714	4	123.5	2.7	19
O&M costs	49.9	33.7	35.9	70	39.2	44.1	31	111.3
Fixed costs	9.8	6.9	10.6	13.2	20.6	1.6	8.7	31.6
Levelized cost	59.7	40.5	46.4	83.2	59.8	45.4	39.7	142.9

*ROR = Run of River. ** Capacity is in MWe
SOURCE: IEA (2005) Projected Costs of Generating Electricity 2005 Update, OECD.
Note: Discount rate is 5 percent.

For levelized cost estimation, the IEA applied two discount rates, 5 and 10 percent, and compared the economics of large and small hydro power plants. At 5 percent discount rate, hydroelectricity generation costs range between some 40 and 80 USD/MWh for all plants except in Japan where they reach more than 140 USD/MWh. O&M costs account in all cases for less than one third of total levelized generation costs.

At 10 percent discount rate, hydroelectricity generation costs range between 65 and 100 USD/MWh for most plants but reach nearly more that 240 USD/MWh for the Japanese plant. The predominant proportion of investment in total levelized generation costs explains the large difference between levelized cost estimates at 5 percent and 10 percent discount rates. The O&M costs, at 10 percent discount rate, are only a marginal component, representing some 10 percent or less of the total except for the run of river hydro plant in Greece, Table 3.4.

Table 3.4
Levelized Generation Costs of Hydro Power Technology in Selected Countries
(2003 USD/MWh)

	Australia	Australia	Czech	Ger.	Greece	Greece	Slovak	Japan
Plant type	ROR *	Small	Small	Small	ROR*	Dam	ROR*	ROR*
Capacity**	14	1.5	3	0.714	4	123.5	2.7	19
O&M costs	91.2	56.7	64.9	132.9	63.9	83.4	56.6	210.3
Fixed costs	9.8	6.9	10.5	13.2	20.6	1.6	8.7	31.6
Levelized Cost	101.0	63.6	75.4	146.1	84.5	84.0	65.3	241.9

*ROR = Run of River. ** Capacity is in MWe
SOURCE: IEA (2005) Projected Costs of Generating Electricity 2005 Update, OECD.
Note: Discount rate is 10 percent.

The third set of estimates is based on a study conducted by the California Energy Resources Commission (CEC)[16] which covered comparative costs of hydro power plants along with other electricity generation technologies in the state of California. The CEC study produced forward estimates of levelized costs of hydroelectricity up to the year 2013, along with other renewable and nonrenewable central station electricity generation resources, based on each technology's operating and capital cost. The cost estimates were intended to provide general guides about expected costs of different technologies for policy makers to assist resource planners in screening generation options. The CEC study used constant prices by referencing all costs to the year 2002 (base year=2002), for calculating levelized costs. Table 3.5 shows the salient assumptions and levelized cost of California hydro electricity generation.

Table 3.5
Levelized Costs of California Hydro Power Electricity Generation
(2002 USD)

Gross capacity (MW)	100
Availability/year (%)	42.5
Availability/year (hours)	3,723
Equipment life (hours)	262,800
Equipment life (years)	30
Maintenance outage (days)	10
Forced outage rate (%)	1.4
Hours per year operation (hour/year)	120
Capacity factor (%)	39.8
Capital ($/MWh)	60.37
Levelized costs (cents/kWh)	6.04

SOURCE: CEC (2003). Comparative Cost of California Central Station Electricity Generation Technologies

The fourth set is derived from the US Department of Energy (DOE)[17]. The methodology of this study is similar to the EIA and CEC. The DOE based capital cost on estimates available from 21

16 CEC (2003): Comparative Cost of California Central Station Electricity Generation Technologies.

17 DOE (2004) Hydropower: Partnership with the Environment.

hydroelectric plants that commenced operating during 1993. The median value is $2,000/kW. The plants range in capacity size from 125/kW installed capacity to 32.4 MW, averaging 4.81 MW of capacity. The capital cost per kW in capacity range is $735 to $4,778. On the other hand, operating costs include supervising, engineering and rent expenses. Maintenance costs include labor, material and other costs for preserving the operating efficiency and/or physical condition of the plant.

Utilizing these assumptions, the DOE reports that in the US, the costs of generating electricity from hydro sources for an average size hydro plant of 31 MW is in the order of 23.6 mills or 2.4 cents per kWh. Table 3.6 displays the breakdown of the DOE cost estimates.

Table 3.6
Average Costs of US Hydro Power Electricity Generation
(2001 USD)

Average size	31 MW
Capacity factor	40-50%
Operating life	50^{+} years
Capital cost $/kW	$1,700-2,300
Operating cost per kWh	0.7 ¢
Levelized cost per kWh	2.4¢

SOURCE: US DOE (2004): Hydropower Partnership with the Environment.

Finally, note that data on the economics of hydro pumped storage is scanty and tends to involve engineering relationships. That is, pumped storage facility operation is often modelled as a simple generator, without representing the off-peak pumping or the opportunities for optimal scheduling. For instance, in 1997 USD, Synapse estimated that the running cost of pumped storage hydro can be estimated based on 2 cents per kWh pumping energy at an efficiency of 76 percent (2/0.76 cents/kWh).[18]

[18] Synapse Energy Economics, Inc. "Horizontal Market Power in New England Electricity Markets: Appendix B: Data Assumptions for Modeling the New England Electricity Market".

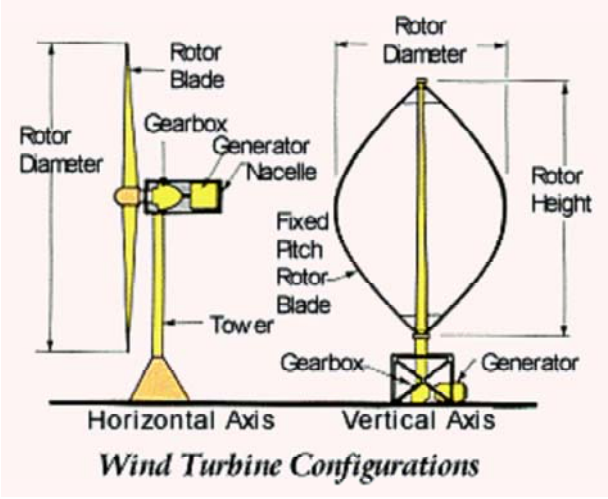
CHAPTER 4
WIND POWER PLANTS

4.1 Overview

Wind power, a renewable source of electricity generation, has recently become of interest to policy makers. This chapter will provide a brief description of wind technology, performance and their associated costs.

4.2 Wind Turbine Technologies

Electricity is generated by transforming the kinetic energy of the wind using turbines. There are two fundamental styles of electric wind turbines: horizontal axis or vertical (egg beater style) axis designs. The horizontal design has proven to be more efficient on a number of dimensions. Consequently, the global commercial market almost exclusively uses the horizontal style turbines.



SOURCE: The Most Frequently Asked Questions About Wind Energy" by American Wind Energy Association (AWEA), http://www.awea.org/pubs/documents/FAQ2002 percent20- percent20web.PDF

The key components of a wind turbine comprise:

- blades, or a rotor, which translate the wind's kinetic energy into rotational shaft energy;
- an enclosed space called a nacelle, that includes a generator, a gearbox[19]. and a drive train;
- a tower, to hold up the drive train and rotor; and
- electronic equipment such as controls, electrical cables, ground support equipment, and interconnection equipment

19 Some turbines operate without a gearbox.

Wind turbines are designed to produce high quality, network frequency electricity whenever enough wind is available. Current generation turbines typically use three blades, with their speed and power controlled by either pitch or stall regulation. The most common regulation is pitch; it entails changing the angle of the blades. In contrast, stall regulation entails controlling the mechanical rotation of the blades. The blades are made from composite materials using fibreglass and epoxy or fibreglass and polyester, at times in a blend with carbon and wood. The kinetic energy for the blade rotation is transmitted to an electrical generator by way of a gearbox and drive train. Otherwise, the generator can be linked directly to the blades using a "direct drive" configuration. Current technology permits turbines to operate at varying speeds, thereby facilitating integration with the electricity grid. The nacelle encloses the gearbox, generator, and other control equipment. Tubular towers hold up the blades and nacelle. Both the nacelle and rotor are able to shift or "yaw"; a feature that allows for favorable positioning against the prevailing wind.

The current generation of turbines is far superior to their predecessors built in the 1980s when the manufacture of commercial wind turbines began in earnest. At the time the Danish technology dominated, producing 20-60 kilowatts (kW) turbines with blade diameters of around 20 metres (m). Since then, wind turbine generators have increased in capacity to 2 megawatts (MW) and above, with blade diameters of 60-90 m. The largest turbine currently in production has a capacity of 4.5 MW and a rotor diameter of 112 m. Therefore a land-based wind plant (farm) rated at 50 MW would be composed of twenty or more turbines. The efficiencies of turbines have increased dramatically through the following improvements: more powerful rotors, larger blades, improved power electronics, better use of composite materials and taller towers. Land use is saved since it now takes fewer turbines to generate electricity at a given rate. The power of wind turbines has increased more than 200-fold since the early 1980s. Recently larger turbines, in the 1.5 to 2.5 MW range, have more than doubled their global market share from 16.9 percent in 2001 to 35.3 percent in 2003.

4.3 Performance Characteristics

The principal performance drivers of wind power economics are electricity production (dependent on average wind speed) and the turbine lifetime. Site selection is crucial for attaining economic viability as electricity production is highly dependent on wind conditions. A 1 MW turbine, depending on wind conditions at its site, can produce sufficient electricity for up to 650 households. The fuel for a wind power station is the wind resource available at its location so incremental changes in wind have a significant effect on the commercial value of a farm. The power of wind increases eightfold with a doubling of the average wind speed; therefore small changes in average wind speed can create substantial variation in performance. For example, at a given site a rise in average wind speed from 6 metres per second (m/s) to 10 m/s amplifies the amount of energy generated by a wind farm by over 130 percent.

Wind power development requires comprehensive and dependable information about a site's wind resource characteristics including: the strength, regularity, and directionality of wind. Ontario's land-based wind resource (sites with average wind speed over 7m/s) has been

estimated at 7500MW.[20] There are currently approximately 6200 MW in Wind Power Projects registered in response to RFPs with the IESO in Ontario. The wind resource is measured by a classification that increases according to average wind speed. Class[21] 4 (and above) wind power sites are characterized by average wind speeds higher than 7m/s and are considered to be commercially viable in Ontario with tax and market incentives. Class 7 sites have average wind power over 8.8 m/s are considered competitive with all electricity generation sources.

Wind is intermittent by nature and the actual electricity generated by a turbine, measured by the capacity factor, will vary accordingly. The average annual capacity factor of modern land-based wind turbines will vary from 25 to 40 percent.[22] A recent study by the Canadian Wind Energy Association (CanWEA) found that in Ontario the capacity factor experiences seasonal variation as winds are typically stronger in the winter (capacity factor rises to a high of 47 percent) than in the summer (capacity factor drops to a low of 19 percent).[23] The intermittent nature of wind creates balancing issues for the system operator; a secondary source of generation is required for those times when the wind is not blowing. The need to balance off electricity is mitigated substantially if wind generation assets are geographically dispersed. The aforementioned CanWEA study suggests that an additional 200 MW of wind would require only 37 MW of balancing generation. Recent improvements in forecasting the energy output from wind farms have also diminished system integration issues.

Wind turbines have a design life of 20 years; they can run continuously, unattended and with low maintenance with some 120,000 hours of active operation. The operating availabilities of wind turbines, the percentage of the time they are available for operation, is extremely high at 98 percent. Among electricity generating technologies, wind turbines have the highest reliabilities.

Once a wind farm is constructed and operational it can be supervised and managed at a distance. A mobile crew performs maintenance; approximately two workers are needed for every 20 to 30 turbines. A current generation wind turbine requires about 40 hours per year of maintenance.

4.4 Capital and Operating Costs

The principal cost drivers of wind power economics are investment costs and operation and maintenance costs. We summarize, in Table 4.1, cost estimates for wind generation from a report titled "Projected Costs of Generating Electricity".[24] The report considered 19 wind plants in 10 countries. Only one wind power plant from North America participated in the study – a US onshore plant- and we have reported its results separately. Of the remaining 18 plants, 16 are onshore and the remaining 4 are offshore. The US plant is assumed to operate at an annual capacity factor of 33 percent. The onshore plants in other countries are assumed to operate at a capacity between 17 percent-38 percent; whereas the offshore plants operate at a capacity

20" Ontario WindPower Taskforce Industry Report and Recommendations"

21 Wind sites are ranked from Class 1 to Class 7. Class 1 is for sites with average wind speeds less than 5.6 m/s.

22 "The Most Frequently Asked Questions About Wind Energy" by American Wind Energy Association (AWEA) http://www.awea.org/pubs/documents/FAQ2002%20-%20web.PDF

23 "An Analysis if the Impacts of Large-Scale Wind Generation on the Ontario Electricity System", CanWEA

24 The study was issued, in 2005, jointly by the OECD, the International Energy Agency, and the Nuclear Energy Agency.

ranging from 35 percent-45 percent. All numbers are reported in USD as of July 1, 2003. Construction of a plant is expected to take 1-2 years. Two sets of levelized costs are reported assuming a 5 percent and 10 percent discount rate respectively. The US plant is assumed to have an economic life of 40 years. The expected economic life ranges from 20-30 years for onshore plants in other countries and 20-25 years for offshore plants.

Table 4.1
Levelized Costs of Generating Electricity by Wind Power
(2003 USD)

	US (Onshore)	Other Countries (Onshore)	Other Countries (Offshore)
Capacity MWh	50	3-72	120-300
Overnight Cost USD/kW	1,024	976-1,634	1,637-2,622
Levelized @ 5%Discount Rate USD/MWh:			
Capital Costs	21.5	27.2-76.8	33.3-59.2
O & M Costs	9.6	4.9-26.3	17.2-35.8
COE	31.1	33.5-92.3	50.5-94.3
Levelized @10%Discount Rate USD/MWh:			
Capital Costs	38.1	39.8-128.8	44.8-87.7
O & M Costs	9.6	4.9-26.3	16.9-35.8
COE	47.8	46.1-144.2	66.0-123.4

SOURCE: Projected Costs of Generating Electricity by (OECD, NEA, IEA) 2005

In 2003, the European Wind Energy Association (EWEA) published a report titled "Wind Energy-The Facts". The costs of wind power in Europe are outlined in Volume 2, "Costs & Prices". The report estimates costs for a land based wind farm made of medium sized turbines ranging from 850-1,500kW. Turbines are assumed to have an economic life of 20 years. All costs are in 2001 prices. The analysis does not consider taxes, depreciation or risk premia. Levelized costs are reported, at discount rates of 5 percent, 7.5 percent and 10 percent, for each areas with low, medium and high average wind speeds. The results are summarized in Table 4.2.

Table 4.2
Levelized Costs of Generating Electricity by Wind Power in Europe
(2001 Euro)

	Low Avg. Wind Areas (Inland)	Med. Avg. Wind Areas (Inland)	High Avg. Wind Areas (Costal)
Full load hours per year	1,500-1900	1900-2500	2500-2900
Investment Cost €/kW	900-1,100	900-1,100	900-1,100
O & M Costs €cents/kWh	1.2	1.2	1.2
Average Wind Speed[25]	5.4-6.2 m/s	6.3-6.8m/s	6.9+ m/s
Levelized Cost@ 5% Dis. €cents/kWh	6.5	5	4
Levelized Cost@ 7.5% Dis. €cents/kWh[26]	7.7	6	5
Levelized Cost@ 10% Dis. €cents/kWh	9	6.5	5.5

SOURCE: EWEA 's "Wind Energy-The Facts Volume 2, Costs & Prices"

The American Wind Energy Association (AWEA), in a 2005 publication titled "The Economics of Wind Energy", outlines the economics of a 50-MW wind farm at a site with average wind speeds between 13-17 mph (5.8-7.5 m/s). The estimates assume the plant operates at a capacity factor of 35 percent which results in annual power production equal to 150 million kWh. Gross revenues are assumed to be $6 million per annum. Expenses are distributed proportionately as follows: Debt 60 percent, Distribution 22 percent, Operation and Maintenance 8 percent, Land, property taxes or rent 5 percent, and Mgt. Fees insurance 5 percent. In addition, the following assumptions are made: a power purchase price of $0.04 USD/kWh, equipment is depreciated over five years and a production tax credit (PTC) of 1.5 c/kWh adjusted for inflation accrues to the producer for the first 10 years. The cost of debt is assumed to be 9.5 percent. The results are summarized in Table 4.3. The report suggests that there are significant economies of scale to lager wind farms.

Table 4.3[1]
Levelized Costs of Generating Electricity by Wind Power in USA

Project Size	50 MW
Capital Cost	$1.3 million per MW
Financing	60% debt, 40% equity
Average Wind Speed m/s	Levelized Costs of Electricity USD/kWh[2,3]
7.15	$0.048
8.08	$0.036
9.32	$0.026

SOURCE: AWEA's "The Economics of Wind Energy"

1 The year of prices not stated in the article.
2 Different average wind speeds lead to different capacity factors and different levels of electricity production.
3 Includes PTC

25 Taken from EWEA's "Wind Power Economics".

26 Numbers visually approximated from Figure 4.2 in EWEA's "Costs & Prices".

As part of our due diligence we contacted Claude Mindorff, Advisor Wind Sector, at Brascan Power, an Ontario wind power developer. Mr. Mindorff provided estimates based on his market research that we share in the tables below. Turnkey costs have risen dramatically in the past year, ranging from $1,850-$2,300/kW depending on project size. This is up from $1,700-$1,800/kW in 2004. According to Mr. Mindorff, these cost increases are a result of an increase in steel prices and pent up demand from US developers. The production tax credit (PTC), a federal subsidy in the US, expired in 2003 and was not renewed by Congress until November of 2004. As a consequence 2004 saw little wind power development in the US, as developers waited for the PTC to be renewed. The subsequent flurry of US development in 2005 has led to tower/blade shortages and increased project lead times to 18 months up form 9 months a year ago and as one might expect, turnkey prices have risen with the increase in demand. Mr. Mindorff expects prices will remain elevated for the next few years but hereafter will return to $1,700-$1,800/kW. Much of the manufacturing of wind components is done outside of North America. As wind generation becomes more significant this is likely to change. Mr. Mindorff points to the level of wind support by the province of Quebec that has led to wind manufacturing being established in the province (GE is building a plant there). He suggests that if Ontario made a long term commitment to increasing generation by wind in a significant fashion that this would bring costs down as transportation costs are significant due to the large size of components.

According to Mr. Mindorff wind technologies are largely mature, having attained 50 percent of the theoretical maximum of 56 percent maximum energy available. Future gains will be made in energy conversion (direct drive) frame size efficiencies, blade designs for low wind speed. Cost of materials will largely drive design choices and ultimate $/MWh. Cost will be reduced by improvements to component erections that will reduce the required crane sizes even as wind equipment becomes larger. The wind turbine generation industry is developing new blade designs specifically for Canada and north eastern USA; these designs should be available within the next 2-3 years. Mr. Mindorff expects the new blade designs will at most achieve a 3-5 percent higher capacity factor or generate 6-10 percent more energy.

Table 4.4
Perfromance and Costs of Wind Power Generation in Canada by Brascan
(2005 CDN$)

Performance:	
Plant Size	100 MW
Economic Life[1]	40 years
Availability	97+%
Efficiency	90%
Forced outage rate	1-3%[2]
Lead time	Currently 18 months, Average 12 months
Financing and Costs:	
Overnight Costs[3]	$1,845-$2,250/kW
Annual O & M Costs per turbine[4]	$10,000-$40,000
Fixed Cost of Regulatory and PPA Approval	1.5 Million
Capital Structure	70%Debt/30%Equity
Ongoing Annual Capital Costs:[5]	
Years 2-9	$2 Million
Years 10-14	$4 Million
Year 15[6]	$12 Million
Years 16-23	$2 Million
Years 24-40	$4 Million
Levelized Costs @ 9% Discount rate	9.5c/kWh[7]

SOURCE: Discussions and materials provided by Claude Mindorff, Advisor Wind Sector, Brascan
[1] Assumes a major retro fit somewhere in the 15th -20th year, otherwise economic life would only be 20 years.
[2] Could be as high as 15 percent in a weak grid where low voltage ride through (LVRT) capabilities are too restrictive.
[3] Calculated by deduction $5 Million from total turn-key constructions costs of $200Million.
[4] Wide variation depends on services contracted. Warranty coverage in the first three years from the manufacturer is tied to both availability and the performance warranty requested by the owner. Turbine manufacturers tie warranties to maintenance contracts and you can get easily 98 percent availability It costs roughly $10,000 per year per turbine for every point above 95 percent availability. Subsequent to three years the general practice is to bring in a contractor to do the full O&M.
[5] Parts required to keep the wind farm functioning; retrofit arbitrarily aassumed by CERI to occur in 15th year. See note 1.
[6] Retrofit arbitrarily aassumed by CERI to occur in 15th year. See note 1.
[7] Mr. Mindorff suggests that this cost is based on recent price increases and that in 2004 these prices were 8.0 c/kWh. See text discussion above table.

Robert Hornung, president of CanWEA, also sent us information on cost and performance data. The data are summarized in the Table 4.5. Mr. Hornung suggests that the RFP winners had levelized costs that averaged $80/MWh. He states"It is important to recognize that levelized costs are partly a function of government policy, including tax policy. What is the policy on transmission upgrades? Nobody knows. Are connection tariffs to distribution feeders going to remain? Is the property tax policy going to change? Are depreciation rates able to be utilized, or will they continue to be available only to very large taxable companies? The use of distributed wind energy to reduce line losses on rural feeders should be mentioned. Line losses in Ontario average about 9 percent. Locating wind turbines on existing radial distribution feeders offers an opportunity to reduce line losses, and so such power is worth more to the system. A kilowatt near a customer is worth more than one from a distance."

Mr. Hornung makes the following comments on future technology improvements" Cost improvements in wind technology are more likely to be evolutionary than revolutionary. Materials technology is improving, allowing longer blades, and larger swept area per turbine.

The new generation blades may utilize carbon fiber. Industry volume is increasing, driving economies of scale. Learning curves for wind turbines suggest that cost will decrease by about 3 percent/year, however, this will be affected by changes in materials costs (eg. Steel) and market conditions. Turbine prices have increased recently due to market buoyancy, but this is a short term (i.e. several year) situation. "

Table 4.5
Perfromance and Costs of Wind Generation in Canada by CanWEA
(2005 CDN$)

Performance:	
Economic Life	20-30 years
Lead time	Permitting 2 yrs, Construction 1 yr
Availability	90-96+%
Capacity factor	25%-35%
Financing and Costs:	
Turnkey Construction Costs	$1,700 - $2,100/kWh
Levelized Costs of Electricity:[1]	
Capital Costs	6.0-7.0c/kWh
O & M Costs	1.0-2.0c/kWh
COE	8.0c/kWh

SOURCE: Discussions with Robert Hornung, President CanWEA. According to Mr. Hornung, some of the information supplied is based on input from CanWEA members.
1 Mr. Hornung suggests that the RFP winners had levelized costs that averaged $80/MWh. No discount rate was provided.

Table 4.6 is taken from material provided by the Energy Information Association.

Table 4.6
Cost and Performance Characteristics of a Wind Plant
(2003 US$)

Technology	Wind
Capacity (MW)	50
Heat rate (Btu/kWh)	8,844
Overnight Cost[1] (2003 $/kW)	1,134
Variable O&M (2003 mills[2]/kWh)	4.06
Fixed O&M (2003 $/KW)	26.81
Lead times (Years)	3

SOURCE: Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38
1 Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.
2 mills = 1/10 of one cent.

4.5 Additional Information – Recently Announced Projects

Our presentation concludes with some additional information on recently announced projects in the United States and Canada as presented in tables 4.6 and 4.7.

Table 4.7[1]
Additional Information on Recently Announced Projects in the United States and Canada(CDN$)[2]

Supplier	Turbine	Tower (m)	# Units	CAN$/kW[2]	Project	Date of press release	Source	Notes
Vestas	NM82, 1.65 MW	78	33	$1,186	Crescent Ridge, Illinois	8/11/2004	http://www.ventusvigor.com/modules.php?name=News&file=article&sid=261 and http://www.crescentridgewind.com/news.htm	Supply of turbines & towers
Vestas	V82, 1.65 MW	67	36	$1,455	Nebraska Public Power	11/19/2004	http://uk.biz.yahoo.com/041119/323/f6yc3.html & http://www.nppd.com/About_Us/Energy_Facilities/facilities/milestones.asp	exact EPC cost, including turbines
Vestas	V-80, 1.8 MW		30	$1,644	Copper Mountain, Murdochville, Quebec	8/11/2004	http://www.ventusvigor.com/modules.php?name=News&file=article&sid=260	All-in EPC cost
Vestas	V-80, 1.8 MW	65	38	$1,462	Summerview, Alberta	10/13/2004	http://home.businesswire.com/portal/site/altavista/index.jsp?ndmViewId=news_view&newsId=20041013005212&newsLang=en	All-in EPC cost
Vestas	V-82, 1.65 MW	80	63	$1,889	St. Leon Project, Manitoba	12/3/2004	http://www.gov.mb.ca/chc/press/top/2004/12/2004-12-03-07.html	All-in EPC cost
Vestas	V-80, 1.8 MW		83	$1,497	Rush Lake Project, Regina, Saskatchewan	10/18/2004	Vestas stock exchange announcement	All-in EPC cost
GE Wind	1.5 MW	65	207	$1,315	Blairsburg, Buena Vista, Sac counties, Iowa	10/1/2004	http://www.solaraccess.com/news/story?storyid=7650 http://www.siouxcityjournal.com/articles/2004/09/03/special_sections/progress_industry/c53961430e28e1f686256e630075d7d3.prt	All-in EPC cost
GE Wind	1.5 MW	65	20	$1,600	Magrath, Alberta	8/6/2004	http://www.safewatergroup.org/green%20business%20&%20economics-swg.htm	All-in EPC cost
GE Wind	1.5 MW	80	29	$1,568	Flying Cloud, Iowa	6/21/2004	http://www.alliantenergy.com/stellent/groups/public/documents/pub/au_env_news_012145.hcsp and http://www.ppmenergy.com/cs_fc.html	All-in EPC cost

(Continued on next page).

Table 4.7 (continued)

Supplier	Turbine	Tower (m)	# Units	CAN$/kW[2]	Project	Date of press release	Source	Notes
MHI	1 MW	80	60	$1,538	San Juan Mesa Wind Project, Elida, New Mexico	3/4/2005	http://www.portales-news.com/engine.pl?station=portales&template=storyfull.html&id=3381 and http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_15531_18513-18040-0_0_0-0,00.html	all-in EPC
MHI	1 MW	67	80	$1,224	Caprock Wind Ranch, Tucumcari, New Mexico	10/29/2004	http://www.kobtv.com/index.cfm?viewer=storyviewer&id=14019&cat=NMTOPSTORIES	all-in EPC
GE	1.5 MW		10	$1,959	Berkshire Windpower LLC , Brodie Mtn, Massachusetts	1/23/2005	http://www.boston.com/news/local/articles/2005/01/23/new_local_power_source_is_in_the_wind_1106448118/	all-in EPC, 3.65 cent 22 yr PPA with Massachusetts Municipal Wholesale Electric Company, 25% capacity factor

SOURCE: Claude Mindorff, Advisor Wind Sector, Brascan
1 Not in summary table.
2 Mr. Mindorff converted the USD/Euro prices to Canadian dollars at varying exchange rates values; only his reported Canadian dollar values are reported.

We present below a list of projects recently announced in eastern and central Canada.

Table 4.8[1]
Additional Information on Recently Announced Projects in Canada (CDN$)

Location	Size (MW)	Capital Cost[2] (Million $)	Source	Date of Press Release
Erie Shores, ON	99	186	Http://www.newswire.ca/en/releases/archive/June2005/29/c7273.html	July 13, 2005
Melancthon Grey Project, ON	67.5	120	Http://www.5d2.ccnmatthews.com/scripts/ccn-release.pl?/current/1221044n.html	Dec. 21, 2004
Grand Manan, NB	20	31.2	Http://newswire.ca/en/releases/archive/November2004/15/c2870.html	Nov. 15, 2004
Dark Harbor, NB	20	37.9	Http://www.newswire.ca/en/releases/archive/May2005/16/c9948.html	May 16, 2005
Ventus, PEI	9	18	Http://ventusenergy.ca/NorwayPressReleaseJun05.pdf	June 1, 2005
Eastern Kings County, PEI	30	55-60	Http://www.gov.pe.ca/news/getrelease.php3?number=4131	May 31, 2005
3Ci 3rd Murdochville Project, QC	54	90	Http://www.3cienergie.com/doc/commpresse14032005.pdf	Mar. 14, 2005

SOURCE: Claude Mindorff, Advisor Wind Sector, Brascan
1 Not in summary table.
2 Turnkey costs

CHAPTER 5
COAL POWER PLANTS

5.1 Overview

Since the industrial revolution, coal has been the most widely used fuel for power generation. For this purpose various technologies or components have been developed in order to provide an environmentally satisfactory method of using coal as a combustion fuel for power generation.

A basic approach to the cleaner use of coal is to reduce emissions by reducing the formation of pollutants. A parallel approach is to develop more thermally efficient systems so that less coal is used to generate the same amount of power.

Clean Coal Technologies (CCTs) are those that facilitate the use of coal to meet various regulations covering emissions[27], effluents, and residues. The CCTs can be categorized into two major groups of combustion and gasification.

Combustion technologies can be categorized into pulverized coal combustion with sub- critical or supercritical steam cycle;and advanced clean coal technologies such as fluidized-bed combustor (FBC), pressurized fluidized-bed combustors (PFBC), and atmospheric fluidized-bed combustors (AFBC).

This chapter provides a brief description of coal combustion technologies. Coal gasification technology will be described in the next chapter.

5.2 Sub-Critical and Supercritical Steam Pulverized Coal Combustion

Pulverized coal combustion[28] (PCC) is the most commonly used method in coal-fired power plants. The pulverized coal power plant design is based on the utilization of pulverized coal feeding a conventional steam boiler and steam turbine.

Before coal arrives at the power plant one way of cleaning the coal is by simply crushing it into small chunks and washing it in the coal preparation plants. The coal floats to the surface while the sulfur impurities sink. Not all of coal's sulfur can be removed by washing because some of the sulfur in coal is chemically connected to coal's carbon molecules (organic sulfur).

Most modern power plants are required to have special devices installed that clean the organic sulfur from the coal's combustion gases before the gases go up the smokestack. The technical

27 When coal burns, the impurities are released into the air. Sulphur can then combine with water vapor form acid rain while carbon carbon can combine with oxygen in the air to form carbon dioxide.

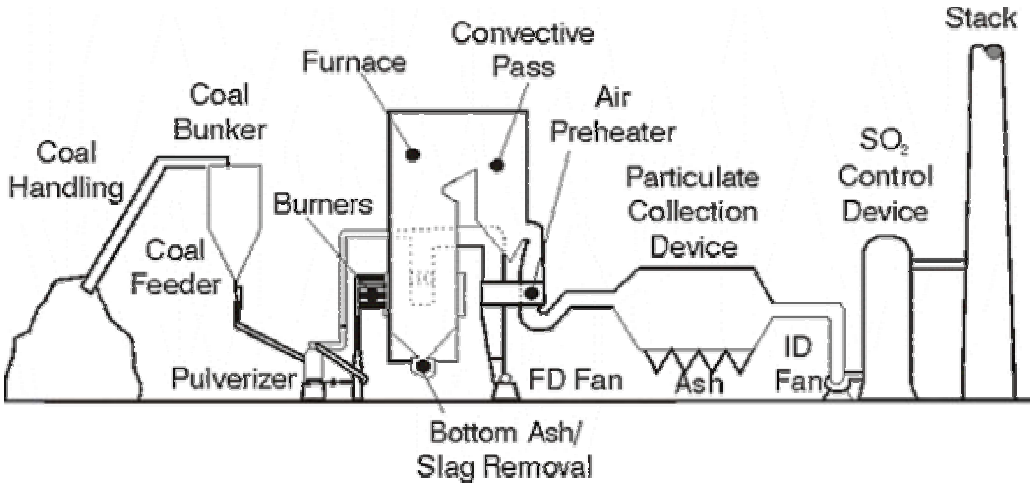
28 The PCC refers to any combustion process that use very finely ground (pulverized) coal in the process.

devices are called flue gas desulphurization (FGD) units or scrubbers that scrub the sulfur out of the smoke released by coal combustion[29].

Most scrubbers rely on a common substance found in nature called limestone. Limestone can be made to absorb sulphur gases like a sponge absorbs water. In most scrubbers, limestone is mixed with water and sprayed into the coal combustion gases (called flue gases). The limestone captures the sulphur and "pulls" it out of the gases. The limestone and sulphur combine to form either a wet paste or a dry powder. In either case, the sulfur is trapped and prevented from escaping into the air.

Figure 5.1 shows a simple flow diagram of a PCC plant. The coal is prepared by grinding (typically, 70 percent of the coal is ground to pass through a mesh screen) to a very fine consistency for combustion. Then pulverized coal is blown with part of the combustion air into the plant through a series of burner nozzles. Combustion takes place at temperature from 1300 to 1700 C.

Figure 5.1
A Simple Schematic Flow Diagram of Pulverized Coal Combustion



Ash is formed in the combustion chamber while coal combusts. The primary advantage of PCC combustion is the very fine nature of the fly ash[30] produced. In general, PCC combustion results in approximately 65 percent–85 percent fly ash, and the remainder is coarser bottom ash[31] or

29 There is also a family of new technologies that work like "scubbers" by cleaning NOx from the flue gases (NOx Scubbers). Some of these devices use special chemicals called "catalysts" that break apart the NOx into non-polluting gases. Although these devices are more expensive than "low-NOx burners," they can remove up to 90 percent of NOx pollutants.

30 Fly ash is the coal ash that exits a combustion chamber in the flue gas and is captured by air pollution control equipments such as electrostatic precipitators, baghouses , and wet scrubbers.

31 Bottom ash consists of agglomerated ash particles formed in pulverized coal boilers that are too large to be carried in the flue gases and impinge on the boiler walls or fall through open grates to an ash hopper at the bottom of the boiler. Bottom ash is typically gray to black in color, is quite angular, and has a porous surface structure.

boiler slag[32]. Various technologies or components have been developed in order to provide an environmentally satisfactory method of using coal for power production in new plants. The principal developments involve increasing plant thermal efficiencies by raising the steam pressure and temperature, and ensuring that flue gas cleaning units meet emissions limits and environmental requirements.

Since both the highest and lowest temperatures of the working fluid govern the efficiency of the plants, strict temperature and pressure limits are indicative of more advanced technology.

Most of the PCC plants use sub-critical steam cycles with pressures less than 22 megapascals (MPa) while supercritical steam cycles utilize steam at a pressure of 24 MPa, and temperature ranges (540 to 560 C). The higher steam pressure in supercritical plants results in higher energy efficiency.

5.3 Atmospheric and Pressurized Fluidized Bed Combustion

Fluidized bed combustion (FBC) processes are commonly used with high-sulphur coal. In a typical coal boiler, coal would be crushed into very fine particles, blown into the boiler, and ignited to form a long, lazy flame in a "fluidized bed boiler" the red-hot mass of floating coal (called bed) would bubble and tumble around which is called fluidized.

In a fluidized bed boiler, upward blowing jets of air suspend burning coal, allowing it to mix with limestone that absorbs sulfur pollutants. As coal burns in a fluidized bed boiler, it releases sulphur but the limestone tumbling around beside the coal captures the sulfur. A chemical reaction occurs, and the sulfur gases are changed into a dry powder that can be removed from the boiler.

The Atmospheric Pressurized Fluidized Bed Combustion (AFBC) plants operate at atmospheric pressure, and NOx generation is minimized due to lower combustion temperatures (815-875^{o} C) than in conventional PCC plants.

The Pressurized Fluidized Bed Combustion (PFBC) plants are typically more compact than similar capacity AFBC and PCC plants due to the boiler, cyclones (cone-shaped air-cleaning), bed re-injection vessels, and associated hardware that are encapsulated in a pressure vessel.

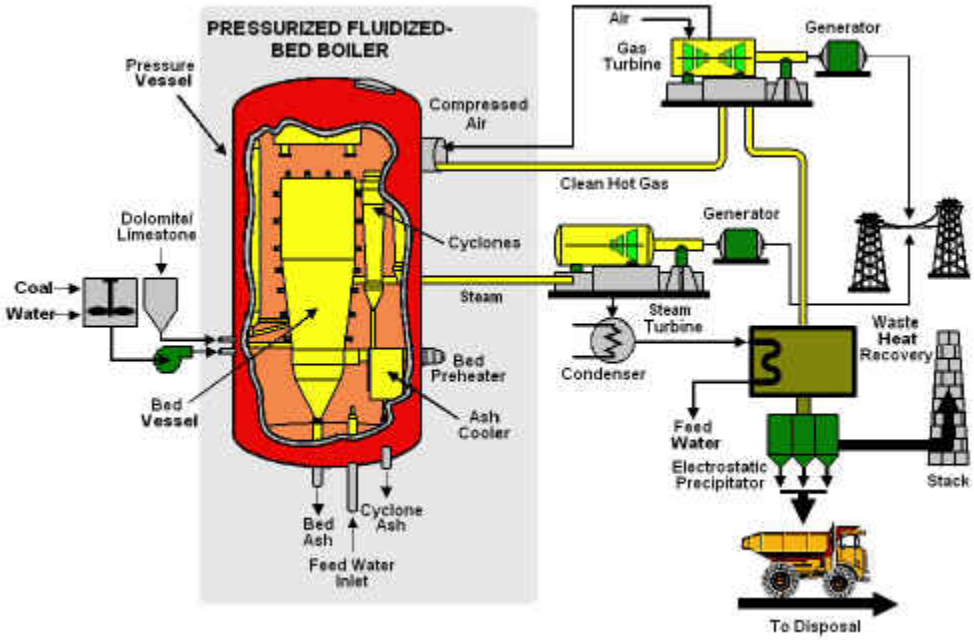
The PFBC is a more efficient way to burn coal because it uses less fuel to produce the same amount of power. Higher efficiency reduces the amount of carbon dioxide released from coal-burning power plants.

The PFBC plants use the same process as AFBC plants to fluidize or float coal/sorbent mixtures. The operating temperature of fluidized beds is between 760 and 870^{0} C, approximately half the temperature of a conventional boiler. In both technologies the use of both steam and gas turbines improve performance by creating a highly efficient combined cycle system.

32 Boiler slag is a molten ash collected at the base of slag tap and cyclone boilers that is quenched with water and shatters into black, angular particles having a smooth glassy appearance.

Figure 5.2 shows a typical PFBC plant for combined steam and electricity generation. The hot, clean combustion gases enter the gas turbine for electricity generation. Also the hot gases exiting the gas turbine, absorbing more heat from a tube bundle in the fluid bed, enter the steam turbine and generate more electricity.

Figure 5.2
Flow Diagram of Pressurized Fluidized Bed Combustion[33]



5.4 Performance Characteristics

The PCC boilers have been built to match steam turbines that have outputs between 50 and 1300 MWe. In order to take advantage of the economies of scale, most new units are rated at over 300 MWe, but there are relatively few really large ones with outputs from a single boiler/turbine combination of over 700 MWe. This is because of the substantial effects such units have on the distribution system if they should 'trip out' for any reason, or be unexpectedly shut down.

The overall thermal efficiency of some older, smaller units burning poor quality coals in some cases can be less than 30 percent. Most of the PCC plants with sub-critical steam cycles are very reliable, but their efficiency is in the region of 34 to 36 percent.

New plants with supercritical steam, however, can now achieve overall thermal efficiencies in the range of 43 to 45 percent and they are already commercially viable[34]. Increasing the steam pressure and temperature from 25 Mpa and 540^0 C to 30 Mpa and 600^0 C can increase the thermal efficiency by nearly 2 percentage points. New high-temperature alloys are under

33 http://www.netl.doe.gov/cctc/summaries/tidd/tidddemo.html

34 IEA Clean Coal Center, http://www.iea-coal.org.uk/templates/ieaccc/content.asp?PageId=65

development with the aim of facilitating steam temperatures as high as 700^0 C. This could achieve net efficiencies of 50 percent[35] with PCC.

The necessary emission control measures can be taken with a relatively small effect on overall thermal efficiency. The operating temperatures of fluidized beds are between 760 and 870^0 C, approximately half the temperature of a conventional boiler. This relatively low temperature is below the threshold where thermally-induced NOx[36] forms. Thus, the fluidized bed designs have reduced SO_2 and NOX emissions when compared with PCC designs. In addition, fluidized bed combustion can use high-ash coal whereas conventional pulverized coal units must limit ash to relatively low levels[37]. Fluidized bed boilers can also burn other materials such as wood and tires.

The PFBC design allows for potentially greater efficiency, reduced operating costs and less waste than the AFBC design.

One of the best ways to reduce NOx is to prevent it from forming in the coal burner. For this purpose excess fuel should be in the combustion chamber ratherthan excess air. Under these conditions, most of the oxygen in air combines with the fuel, rather than with nitrogen. The burning mixture is then sent into a second combustion chamber where a similar process is repeated until all the fuel is burned. This concept is called "staged combustion" because coal is burned in stages. In the US most large coal-burning boilers are equipped with technology of 'staged combustion". This device can reduce the amount of NOx released into the air by more than half.

The Canadian Electricity Association (CEA)[38] keeps operating statistics on electricity generating units operated in Canada by electric utilities and by Alcan Primary Metal Group. These statistics permit a comparison of reliability and chosen mode of operation (base load, intermediate, peaking) among the different technologies and fuels.

Table 5.1 shows the values of key operating statistics for steam coal fired turbines in 2003, and their average for the period 1999-2003. The definition of operating factor (OP factor), available but not operating factor (ABNOF), forced outage rate (FOR), and derating adjusted forced outage probability (DAUFOP) are defined in Chapter 3**.**

35 IEA Clean Coal Center, http://www.iea-coal.org.uk/templates/ieaccc/content.asp?PageId=65

36 NOx can be produced by any fuel that burns hot enough (around 3000 degrees F the air oxygen and nitrogen molecules break apart and oxygen atoms link with the nitrogen atoms to form NOx), including coal-burning power plants.

37 A comparison of Combustion Technologies for Electricity Generation, Appendix 4, Pembina Institute, July 24, 2001, http://www.pembina.org/pdf/publications/appendix4.pdf

38 Canadian Electricity Association, 2003 Annual Report, Equipment Reliability Information System.

Table 5.1
Operating Charactristics of Canadian Steam Coal Fired Plants

Period	OP Factor (%)	ABNOF (%)	FOR (%)	DAUFOP (%)
2003	80.37	5.19	5.94	9.14
1999-2003	79.12	4.84	6.73	9.38

SOURCE: Canadian Electricity Association, 2003 Generation Equipment Status Annual Report, tables 6.2.9 and 10

The values of "OP FACTOR" and "ABNOF" reflect the degree of utilization of the units, whereas the values "FOR" and "DAUFOP" are measures of reliability.

Over the five-year period 1999-2003 the operating factor of the steam coal fired units in Canada was 79.12 percent; over the same period, the same units were "available but not operating" 4.84 per cent of the time.

The CEA also reports that over the same five-year period the probability that a unit would be unavailable if needed ("DAUFOP") was 9.38 percent.

CERI has concluded that

- If OP FACTOR is high and ABNOF is low then the unit was used for base-load.
- If OP factor is low and ABNOF is high than the unit was used for peaking.
- A less extreme value for either of these factors would result from use in intermediate load.
- The closer the values FOR and DAUFOP are to zero the more reliable is the unit.

Table 5.1 indicates that over the period 1999 to 2003, Canadian steam coal-fired plants operated largely in base-load service, with probability of (100 – 9.38) =90.66 percent that a coal-fired unit would be available if needed.

5.5 Capital and Operating Costs

In 2004, East Harbour Management Services (EHMS)[39] in response to a request by the New Zealand Ministry of Economic development prepared the report "Fossil Fuel Electricity Generation Costs". The details of electricity generation costs for pulverized coal combustion with sub-critical

[39]East Harbour Management Services, Fossil Fuel Electricity Generating Costs, prepared for Ministry of Economic development – New Zealand. June 2004.
http://www.med.govt.nz/ers/en_stats/projections/background-papers/east-harbour/index.html

and supercritical boilers including flue gas desulphurization (FGD) are shown in Table 5.2 and Table 5.3. The information from this table has been used for the levelized cost estimation which is shown in Table 5.3.

For the levelized cost estimation a discount factor of 7.5 percent has been used for over a 20-year plant life. Fuel prices are assumed at $2.50/GJ for bituminous coal on the West Coast, and $3.50/GJ for elsewhere in New Zealand, $3.50/GJ for sub-bituminous coal and $1.50/GJ for lignite coal. If low sulfur coal is available and FGD is not required, unit cost estimates for the coal fired plant are reduced by about 0.6 c\ kWh. All data are shown in New Zealand dollars (NZD) where in September 2003, $NZ 1=US$0.60.

Table 5.2
Costs and Efficiency of Pulverized Coal Combustion
(2003 NZD)

			O&M Cost[2]		
Technology	**Size MW**	**Capital Cost[2] $/kW**	**Fixed $/kW**	**Variable c/kWh**	**Efficiency (HHV) %**
Sub critical pulverized coal (bituminous) with FGD[1]	150	2420	31	0.31	34
Supercritical pulverized coal (bituminous) with FGD	500	1850	31	0.31	38
Supercritical pulverized coal (lignite) with FGD	500	2030	35	0.34	36
Supercritical pulverized coal (sub-bitum.) with FGD	500	1920	31	0.31	38

SOURCE: East Harbour Management Services, Fossil Fuel Electricity Generating Costs, prepared for Ministry of Economic development – New Zealand. June 2004.
NOTES: (1) For a pulverized coal plant, without FGD deduct $170/kW from the capital cost. O&M costs are reduced by approximately 10 percent and there is an approximate 2 percent gain in efficiency. (2) Costs are in September 2003 New Zealand dollars. $NZ 1=US$0.60

Table 5.3
Levelized Costs of Pulverized Coal Combustion Technologies
(2003 NZD - c/kWh

Technology	Size MW	Capital	Fuel	O&M	Tax	Total
Subcritical pulverized coal (bituminous) with FGD	150	3.3	2.6	0.9	0.9	7.7
Supercritical pulverized coal (bituminous) with FGD	500	2.5	3.3	0.9	0.7	7.3
Supercritical pulverized coal (lignite) with FGD	500	2.7	1.5	0.8	0.7	5.7
Supercritical pulverized coal (sub-bitum.) with FGD	500	2.6	3.3	0.7	0.7	7.3

SOURCE: East Harbour Management Services, June 2004.

NOTE: Levelized costs are estimated at 7.5 percent discount rate.

The minimum and maximum lead time for coal plant has been considered 60 and 109 months respectively. The likely lead time is assumed 79 months.

It should be noted that one of the driving forces which is currently encouraging the use of more efficient power plant is the environmental concern for CO2 emissions. One of the less expensive ways of reducing CO2 emissions is increasing the thermal efficiency of converting coal to power. Increasing thermal efficiency has the potential for reducing other emissions per MWe generated, such as those of SO2 and NOx. Overall, higher thermal efficiency can result in reduced costs in new plants for power generation, as less fuel is needed.

The OECD has recently published the findings of an empirical study[40] on the levelized cost of electricity generation. The study applied field surveys and covered a multitude of electricity generating technologies in a few countries including Canada and the USA.

The OECD study applied generic assumptions in order to derive its calculations. Salient assumptions include: economic lifetime (40) years, average load factor for base-load plants (85 percent) and discount rates (5 percent and 10 percent) and base year is July 2003. The electricity generation costs are busbar costs, at the station, and therefore do not include transmission and distribution or environmental costs. Table 5.4 shows the component and levelized cost of electricity generation for coal fired plants.

40 OECD: Projected Costs of Generating Electricity: 2005 Updates.

Table 5.4
Levelized Cost of Electricity Generation - Coal Fired plant
(2003 USD/MWh)

Technologies – Country/plant type	Dis. Rate	Net Capacity Mwe	Overn Const Cost – Musd	Lev. Capital Cost	Lev. O&M	Lev. Fuel Cost	Lev. Electricity Cost
CAN-C:PF(SC)/FGD,LNB,FF	5%	450	594	11.2	6.7	13.1	31.1
CAN-C:PF(SC)/FGD,LNB,FF	10%	450	594	21.4	6.7	13.1	41.2
USA-C1:PF/FGD,SCR,FF	5%	600	696	10	6.6	10.5	27.1
USA-C1:PF/FGD,SCR,FF	10%	600	696	19.5	6.6	10.5	36.5

SOURCE: IEA, Projected Cost of Generating Electricity 2005 Update, OECD, Paris, France.
NOTES: **FGD,** Flue gas desulphurization; **LNB,** Low NO_x burners; **FF,** Fabric filters;**SCR,** Selective catalytic reduction (de NO_x)

The Electricity Market Module (EMM) of The National Energy Modeling System (NEMS) determines the most economical way to supply electricity, within environmental and operational constraints. The EMM composed of four sub-models of electricity capacity planning, electricity fuel dispatching, load and demand-side management, and finance and pricing.

The cost and performance characteristics of new generating technologies that are input to the electricity capacity planning sub-models for coal technology[41] is summarized in table 5.5.

Table 5.5
Cost and Performance Characteristics of Scrubbed Coal Fired plant
(2003 USD)

Technology	Scrubbed Coal
Capacity (MW)	600
Heat rate (Btu/kWh)	8,844
Overnight Cost[1] (2003 $/kW)	1,213
Variable O&M (2003 mills[2]/kWh)	4.06
Fixed O&M (2003 $/KW)	24.36
Lead times (Years)	4

SOURCE: Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38
[1] Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.
[2]mills = 1/10 of one cent.

41 Energy Information Administration (EIA), Assumptions to the Annual Energy Outlook 2005 with Projection to 2025. http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf

CHAPTER 6
COAL AND BIOMASS GASIFICATION

6.1 Overview

In Chapter 5, we introduced the PFBC and AFBC as one of the newest ways to burn coal cleanly. There is another new way, which doesn't burn the coal but instead gasifies the coal (gasification). In this process the impurities in coal like sulfur, nitrogen and many other trace elements are almost entirely filtered out when coal is gasified.

The objective of this chapter is to provide background information on the process and technology of gasification and synthetic gas production. Then integrated gasification combined cycle technology with fuel choice of coal and biomass will be described.

6.2 Gasification and Synthetic Gas Production

Synthetic gas (syngas) is the name given to gasses of varying compositions that are generated from thermal conversion of any kind of hydrocarbon, including natural gas, coal, oil, gases from waste-to-energy facilities including biomass, and municipal solid waste (MSW).

Synthetic gas is a mixture containing hydrogen (H_2) and carbon monoxide (CO) that can be used as a source of energy for internal combustion engine, or as a source of chemical building blocks in petrochemical plants. In addition, the hydrogen of syngas can be extracted and used in fuel cells.

Figure 6.1
Synthetic Gases

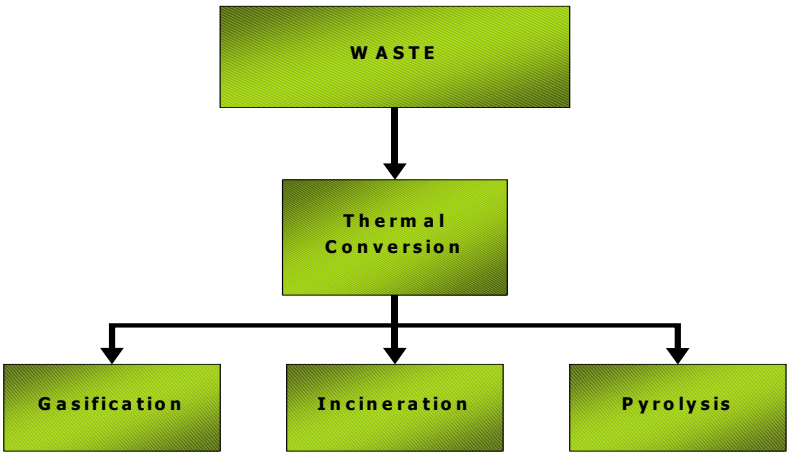


Figure 6.1 shows three types of thermal conversions:[42]

- Incineration: converts the input waste into heat energy and ash.
- Gasification: breaks down hydrocarbons into the gases by controlling the amount of oxygen present. The results of this process are syngas and solids.
- Pyrolysis: decomposes or degrades the waste in the absence of air and presence of extreme heat. The results of this process are syngas, liquids, and solids.

The term "co-production" refers to those facilities that produce some combination of electricity, heat, fuels and chemicals. Poly-generation is a similar term used to describe the conversion of low value wastes such as pitch or petroleum coke into synthetic gas (H_2 and CO) and other products via gasification.

6.2.1 Gasification and Incineration

Gasification has been in use for more than half a century and is a proven technology currently in operation all over the world. Gasification involves heating a solid fuel material by partially combusting it with insufficient air for complete combustion. This process is known as "partial oxidation of organic material". In this process the majority of carbon (C) is converted into syngas by use of a gasification agent (air, oxygen, and steam).

Incineration is far more proven than gasification. Although often confused with incineration, gasification is significantly different due to partial oxidation which prevents forming sulphur and nitrogen oxides. Gasification operates at very high temperatures (900 to 1100^0c) and produces carbon monoxide and hydrogen. However, incineration produces carbon dioxide and water. Another significant difference is that gasifiers produce syngas that is free of dioxins and furan[43] compounds. Therefore, gasification may provide an alternative source of clean energy to help meet the increasing global demand for steam and electricity generation.

6.2.2 Pyrolysis and Gasification

Pyrolysis decomposes waste in the absence of oxygen at temperatures in the range of 400 to 800°c. The products of pyrolysis are syngas (carbon monoxide, hydrogen, and methane), liquids (complex mix of hydrocarbons and tar) and solids (char, inorganic materials, and metals). Thus, pyrolysis produces one additional product compared to gasification, namely the liquids.

Gasification and pyrolysis offer more scope for recovering products from waste than incineration. When waste is burned in a modern incinerator the only practical product is heat energy, whereas the gases from gasification and pyrolysis can be used as a fuel and feedstock. Furthermore, from waste gasification it is feasible to produce hydrogen, which is recognized as a valuable resource.

42 State-of-the –Art gasification, Peter Heymann Andersen, Head of Department of RAMBOLL.
www.iswa.ch/Info/Documents/WasteToEnergy03/Andersen.pdf

43 Dioxins and furans are the by-products of burning municipal and medical waste.

6.2.3 Fischer-Tropsch Process

Syngas can be burned, separated into carbon monoxide and hydrogen, or converted to a liquid fuel by processes like the Fischer-Tropsch (F-T)[44].

The F-T process is a catalyzed chemical reaction in which carbon dioxide, carbon monoxide and methane are converted into liquid hydrocarbons of various forms. Iron or cobalt is generally used as the catalyst[45].

The principal purpose of the F-T process is to produce a synthetic petroleum substitute. For example, all lubricants, asphalt and wax can be processed and converted to liquid petroleum through the F-T.

6.2.4 Feedstock for Synthesis Gas Production

The feedstock for syngas production varies from fossil fuel and petroleum by- products to clean biomass and municipal solid wastes. Sources of feedstock for syngas can be summarized as:

- fossil fuels (e.g. coal, orimulsion),
- residue of petroleum by-products (e.g. petroleum coke, asphalt, tars),
- processed agricultural and forestry residues (e.g. biomass and wood),
- municipal solid waste (e.g. handling household and commercial wastes), and
- Residues left from recycling materials (e.g. tiers and plastic waste).

6.3 Coal Gasification

As described before, coal can be gasified into synthetic gas (syngas) in various ways by properly controlling the mix of coal, oxygen, and steam within the gasifier**.**

The supply of coal into the system is considerably more complex than with pulverized coal combustion. Some gasifiers use bulky and costly lock hopper systems to inject the coal, while others have the coal fed in as water-based slurry. There are also several options for controlling the flow of coal in the gasification process, such as fixed-beds (not normally used for power generation), fluidized-beds and entrained flow systems.

Integrated Gasification Combined Cycle Technology (IGCC), like pressurized fluidized-bed combustor (PFBC) combines both steam and gas turbines. Figure 6.2 shows a simple diagram of

44 Since the invention of the original process by the German researchers Franz Fischer and Hans Tropsch, working at the Kaiser Wilhelm Institute in the 1920s, many refinements and adjustments have been made, and the term "Fischer-Tropsch" now applies to a wide variety of similar processes.

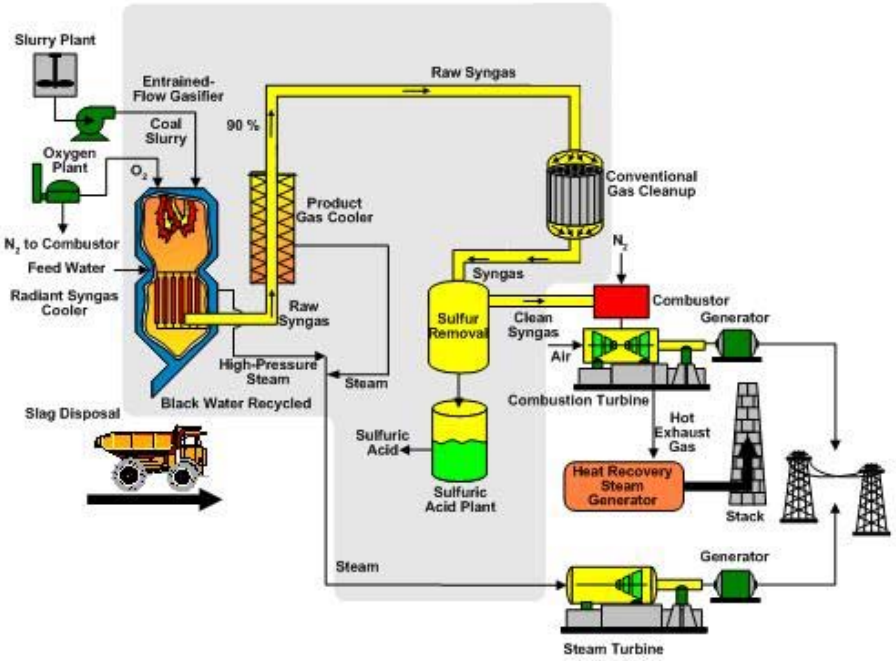
45 http://en.wikipedia.org/wiki/Fischer-Tropsch_synthesis

IGCC configuration[46]. The IGCC system consists of four main stages: feeding, gasifier reactor, gas cleaning and utilization of combustible gas for steam and electricity generation.

The syngas leaving the gasifier must be cleaned of sulfur compounds and particulates. Currently, cooling the syngas to below 100 ^{0} C is required for conventional cleaning, and it is subsequently reheated before combustion. Cleanup of syngas reduces overall plant efficiency and increases capital costs. Alternatively the syngas can be cleaned under high pressure and temperature (hot-gas cleanup), which is more efficient.

After the fuel gas (syngas) has been cleaned, it is burned and expanded in a gas turbine. Steam is generated and superheated in both the gasifier and the heat recovery unit downstream from the gas turbine. The fuel gas is then directed through a steam turbine to produce electricity.

Figure 6.2
Integrated Gasification Power Plant Configuration



6.3.1 Performance Characteristics

A number of IGCC plants around 250 MW_e in size are operating in Europe and the USA. Most use entrained flow and are oxygen blown, and one is based on a fluidized bed and is air-blown. The reliability, capital costs and environmental results of modern gasification technologies have been extensively documented and the technology is fully-commercial**.** Large gasifires are difficult to transport, simply because of their weight and sheer size, and this may prove to restrict their eventual use for sizes above 300 MW_e.

46 http://www.cogeneration.net/IntegratedGasificationCombinedCycle.htm

Depending on the configuration and the level of integration of the various processes the current IGCC plant designs are capable of achieving 40 to 42 percent efficiency with heat rates in the 8,400 to 8,600 MMBTU/KWh range. Currently, the gas cleaning stages for particulates and sulphur removal can only be carried out at relatively low temperature, which restricts the overall efficiency. Higher efficiencies (45 percent) are possible when a high gas inlet temperature to the gas turbine can be achieved.

Gasification by-products are benign, consisting of more than 99 percent pure elemental sulfur and unlike pulverized coal plants, no fly ash is generated. IGCC technology may be considered as the technology of choice since 99 percent or more of the SO2 is removable and the level of NOx emissions are below 100 ppm. Highly integrated plants tend to have long start-up times (compared to PCC plants), and hence may only be suitable for base-load generation.

Integrated gasification is able to compete with existing clean-coal technologies, and any future efficiency gains from advanced turbine designs and a more efficient production of oxygen are expected to widen the gap between gasification and competing clean coal technologies such as circulating fluidized bed (CFB) and supercritical boilers.

Coal gasification could be one of the most promising ways to use coal in the future to generate electricity and other valuable products.

6.3.2 Capital and Operating Costs

The cost of per KW of electricity generation of IGCC is in the range of US$1,200 to $1,400/kW. The cost is 10 to 30 percent higher than pulverized-coal costs.

Depending on the fuel, modern gasification technologies can produce syngas for between $3.50 and $4.50/MMBTU and base-load power for as low as $40/MWh[47].

The IGCC plants can be configured to facilitate CO2 capture. This is because the relatively high pressure of the exhaust gases in an IGCC plant allows for easier CO2 removal[48]. The new gas is quenched and cleaned. The syngas is shifted using steam to convert CO to CO2, which is then separated for possible long term sequestration[49]. The IGCC will be able to achieve production costs 20 to 25 percent lower than other clean coal technologies by capturing CO2 at the source rather than after it has gone up the stack.

The primary constraints or risk to the application of gasification and IGCC plants is capital cost, which is at higher levels than those of competing technologies. The higher costs are mainly related to the advanced clean technologies (high SO_2 removal and low-NOx emissions) while modern gasification plants exceed the environmental regulations in developing countries and new Source Emissions Standards for coal plants.

47 Gasification: the future of power technology, here today. Capital Technology, Inc. (CTI), http://www.capital-technology.com/gasification.html

48 The amount of CO2 emitted from a natural gas-fired power plant is approximately half that emitted from a coal-fired plant.

49 IEA Clean Coal Center, Integrated gasification Coal Cycle
http://www.iea-coal.org.uk/templates/ieaccc/content.asp?PageId=65

The Pembina Institute[50] in 2001 conducted a study for the purpose of comparison of coal combustion options. The result of this study for IGCC is summarized in table 6.1. All costs in this table are illustrated in Cdn$ (US$ has been converted to 1995 Cdn$ at a C$1.50/US$ exchange rate).

Table 6.1
Costs and Efficiency of the Integrated Coal Gasification Plant
(1995 CDN$)

Capacity	MW	100 - 300
Plant Efficiency	%	45
Heat Rate	Gj/MWh	8
CO_2	Kg/MWh	735
Nox	Kg/MWh	0.25 - 0.45
Capital Cost	$Cdn/KW	1800 - 2100
Fuel Cost	$Cdn/MWh	9.44
Total Operating Costs	$Cdn/MWh	14.98 - 15.97
Overall Levelized Cost	$Cdn/MWh	46.04 - 50.61

SOURCE: Pembina Institute

The Electricity Market Module (EMM) of The National Energy Modeling System (NEMS) determines the most economical way to supply electricity, within environmental and operational constraints. The EMM composed of four sub-models of electricity capacity planning, electricity fuel dispatching, load and demand-side management, and finance and pricing.

The cost and performance characteristics of coal integrated gasification combined cycle with and without carbon sequestration to The US National Energy Modeling System (NEMS)[51] is summarized in table 6.2.

50 SOURCE: A comparison of Combustion Technologies for Electricity Generation, Appendix 4, Pembina Institute, July 24, 2001, http://www.pembina.org/pdf/publications/appendix4.pdf

51 Energy Information Administration (EIA), Assumptions to the Annual Energy Outlook 2005 with Projection to 2025. http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf

Table 6.2
Cost and Performance Characteristics of Coal IGCC
(2003 USD)

Technology	IGCC	IGCC/with Carbon Sequestration
Capacity (MW)	550	380
Heat rate (Btu/kWh)	8,309	9,713
Overnight Cost[1] (2003 $/kW)	1,402	2,006
Variable O&M (2003 mills[2]/kWh)	2.58	3.93
Fixed O&M (2003 $/KW)	34.21	40.26
Lead times (Years)	4	4

SOURCE: Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38
[1] Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.
[2]mills = 1/10 of one cent.

The OECD has recently published the findings of an empirical study[52] on the levelized cost of electricity generation. The study applied field surveys and covered a multitude of electricity generating technologies in a few countries including Canada and the USA.

The OECD study applied generic assumptions in order to derive its calculations. Salient assumptions include: economic lifetime (40) years, average load factor for base-load plants (85 percent) and discount rates (5 percent and 10 percent) and base year is July 2003. Table 6.3 shows the component and levelized cost of electricity generation for coal IGCC.

Table 6.3
Levelized Cost of Electricity Generation- Coal IGCC
(2003 USD/MWh)

Technologies - Country/plant type	Dis. Rate	Net Capacity Mwe	Overn const cost-Musd	Lev. Capital cost	Lev. O&M	Lev. Fuel cost	Lev. Electricity cost
USA-C2:IGCC/FGD,SCR,FF	5%	550	751	11.7	6.7	8.9	27.3
USA-C2:IGCC/FGD,SCR,FF	10%	550	751	22.6	6.7	8.9	38.2

SOURCE: IEA, Projected Cost of Generating Electricity 2005 Update, OECD, Paris, France.
NOTES: **FF,** Fabric filters; **SCR,** Selective catalytic reduction (de NO_x), **FGD,** Flue gas desulphurization

The report "Clean Coal Technology Roadmap"[53] presents cost and performance of both pulverized coal (PC) and integrated gasification combined cycle (IGCC) for three periods: present, 210 to 2015, and 2015 to 2025. The report anticipated that in the third period of 2020 – 2025, CO2 capture and storage technologies will be able to deliver near-zero coal emissions for electricity generation.

52 OECD: Projected Costs of Generating Electricity: 2005 Updates.

53 Natural Resources Canada & SaskPower,(CCTRM), Clean Coal Technology Roadmap

The results of this report is summarized in table 6.4. This table indicates that the average capital cost to replace existing facilities with CCT is $1,250 US dollars (USD)/kW of installed capacity. If CO2 capture technology were included, the average cost would be just over $1,900 USD/kW. Using these figures, the annual investment required to replace all existing coal-fired facilities is on the order of US$$900 million – US$1.4 billion/year for the next 25 years.

Table 6.4
Present and anticipated CCTs Performance

Technologies	Capital Cost US$/Kw	Efficiency %	Capital Cost for CO2 Removal US$/KW	COE[1] without CO2 capture US c/KWh	COE with CO2 capture US c/KWh
Present - best Available technology					
Pulverized Coal	1000 – 1200	40 - 43	700 - 900	3.5 - 4.4	6.3 - 7.9
Integrated Coal Gasification	1200 – 1500	40 - 44	300 - 800	4.4 - 4.9	5.7 6.4
Future - 2010 to 2015					
Pulverized Coal	900 – 1100	45 - 50	500 - 600	3.0 - 4.1	3.6 - 4.9
Integrated Coal Gasification	1000 – 1200	45 - 50	200 - 500	3.0 - 4.1	3.3 - 4.5
Future - 2015 to 2025					
Pulverized Coal	900 – 1000	50 - 53	300 - 400	< 3.0	NA
Integrated Coal Gasification	800 – 1000	50 - 60	100 - 300	< 3.0	NA

1 - Cost of Electricity
SOURCE: Natural resources Canada

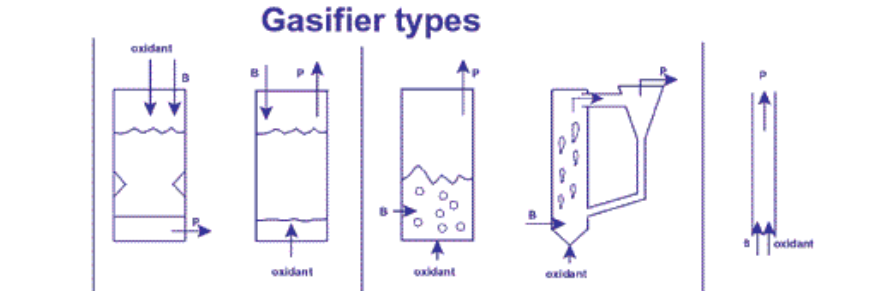
The Royal Academy of Engineering commissioned[54] a study in 2004 for the comparative costs of generating electricity from a number of available technologies in the UK. The report revealed that in 2004, the cost (Pence per KWh) of generating electricity with no cost of CO2 emission was 3.20 pence per KWh, and with CO2 emission the cost increased to 5.10 pence per KWh. The study considered a range of values between zero and £ 30 per ton for the cost of CO2. The upper limit reflects the cost of CO2 sequestration.

6.4 Biomass Gasification

Biomass gasification is a thermal conversion where a solid fuel is converted into a combustible gas. The process of gasification is similar to the coal gasification. A limited supply of oxygen air, steam or a combination serves as the oxidizing agent. The product gas mainly consists of carbon monoxide, carbon dioxide, hydrogen, methane, water, nitrogen and contaminants like small char particles, ash and tars. After cleaning the gas it is suitable for boiler, engine, and turbine use to produce heat and power (CHP).

Several different type gasifiers have been developed with respect to the size and use of the feedstock. Figure 6.3 summarizes the main types of gasifers and their typical operating temperature and scales[55].

Figure 6.3
Gasifiers and Scale of Operations



	Co-current	Counter current	dense	circulating	
T°C	700-1200	700-900	< 900	< 900	≈1500
tars	low	very high	intermediate	intermediate	absent
control	easy	very easy	intermediate	intermediate	very complex
scale	< 5 MW_t	< 20 M_t	10<MW_t<100	20<MW_t<?	> 100 MW_t
feedstock	very critical	critical	less critical	less critical	very fine particles

When biomass decomposes at elevated temperatures, three primary products are formed: gas, bio-oil and char. At high temperatures the bio-oil vapours are decomposed in secondary products

54 The Cost of generating Electricity, A commentary on a study carried out by PB Power for the Royal Academy of Engineering. http://www.world-nuclear.org/opinion/rae-summary.pdf

55 Biomass Technology Group, http://www.btgworld.com/technologies/gasification.html

like gas and tar. Therefore, Pyrolysis[56] offers a flexible and attractive way of converting solid biomass found in forestry and agricultural residues into an easily stored and transported liquid, which can be successfully used for the production of heat, power and chemicals.

The biomass is thermo-chemically converted to liquid bio-oil by using processes called direct liquefaction or fast pyrolysis. The fast or flash pyrolysis processes for creating bio-oil apply rapid heat to small biomass particles at high temperatures in the absence of added oxygen. This process breaks down the biomass structure instantly to produce a high yield of condensable organic liquids. The liquids are typically 65 percent liquid bio-oil, 15 percent solid char and 20 percent gases. The char and gases are often burned in order to dry and pyrolysis the biomass[57].

Biomass characteristics should not be a technical barrier in pyrolysis and gasification and pyrolysis of most biomass can be successful. Bio-oil can offer major advantages over solid biomass and gasification due to the ease of handling, storage and combustion in an existing power station.

6.4.1 Performance Characteristics

Biomass can be used as fuel and it is considered a renewable resource. Biomass can help to relieve concern of fossil fuel reserves and their associated environmental problems. Biomass includes waste from agriculture, forestry, pulp and paper plants, manufacturing and residential waste.

Unprocessed biomass fuel has a relatively low heating value due to its high moisture content. The moisture of biomass fuel can be removed at a temperature above 100^{o}C without experiencing any kind of decomposition, but this change the heat rate. Processing (dry) of biomass fuels would reduce transportation and storage costs and make the fuels easier to feed into a furnace.

The unprocessed green wood at 50 per cent moisture has 4,500 Btu/lb, while after processing the heating content of dried wood increases to 9,000 Btu/lb. The price of biomass fuel varies over a wide range, but certainly their prices are competitive with fossil fuels.

Biomass, through, pyrolysis can be gasified into synthetic gas or converted to liquids of bio-oils. Both products can be used as fuel for steam and power generation. The high water and oxygen content of bio-oils reduces their heating value to less than half the value of petroleum. However, bio-oils are low in viscosity and have been successfully burned in boilers, turbines and diesel engines. Bio-oil can also substitute for light fuel oil and heavy fuel oil according to specifications. Up to 40 percent bio-oil has been added to standard diesel fuel by using surfactants to create a stable mixture. In the future, this mixture might be used as fuel for standard diesel engines in trucks, tractors, construction equipment and forestry equipment.

56 The future for biomass, pyrolysis and gasification: status, opportunities and policies for Europe Contract No: 4.1030/S/01-009/2001, A V BRIDGWATER, Bio-Energy Research Group, Aston University, Birmingham B4 7ET, UK. November 2002

57 NRC, http://www.canren.gc.ca/tech_appl/index.asp?CaId=2&PgId=183

6.4.2 Capital and Operating Costs

Electric power production from biomass has the potential to make a significant contribution to the power mix and substantially reduces environmental impact. To realize these potential contributions, however, biomass power systems must be competitive on a cost and efficiency basis. One aspect of the biomass operational costs is the price of the feedstock. These can be expensive like short rotation coppice (SRC) or cheap (negative) like waste residues. Transportation, fuel handling and processing adds to the cost of the feedstock. Furthermore, labor costs must be minimized through process control and automation. Practical experience is needed to determine the maintenance costs. Remuneration of electricity and heat can also be decisive in the overall economics.

Several economic studies have been made on biomass gasification regarding the feasibility and profitability of this technology. The National Renewable Energy Laboratory[58] conducted a comprehensive study on the cost and performance potential of three biomass-based integrated gasification combined cycle (IGCC) systems. The three gasifier systems chosen for this study were a high pressure air-blown, a low pressure indirectly-heated, and a low pressure air-blown.

For the above project the operating and maintenance costs for the plant were based on an 80 percent capacity factor, Wood costs were assumed to be $46/Mg ($42 per bone dry ton) and the life of the project is assumed to be 30 years.

The levelized cost of electricity generation in current and 1990 constant dollars for IGCC based generation technologies are presented in Table 6.5.

58 Cost and Performance Analysis of Biomass-based Integrated Gasification Combined – Cycle Power System , NREL, 1997, http://www.nrel.gov/docs/legosti/fy97/21657.pdf

Table 6.5
Cost of Biomass Integrated Gasification Combied Cycle
(1996 USD)

	High Pressure Direct Gasifier, Aero-Derivative Gas Turbine	High Pressure Direct Gasifier, Greenfield Plant	High Pressure Direct Gasifier, Advanced Utility Gas Turbine	Low Pressure Indirectly-heated Gasifier, Advanced Utility Gas Turbine	Low Pressure Direct Gasifier, Advanced Utility Gas Turbine
Output (MW)	56	56	132	122	105
Efficiency (% HHV)	36.01	36.01	39.70	35.40	37.90
Capital Cost (TCR, $/kW)	$1,588	$1,696	$1,371	$1,108	$1,350
Operating Cost incl. Fuel	3.42	3.48	3.10	3.27	3.19
($1,000/year)	$13,433	$13,675	$28,702	$27,983	$23,442
COE (¢/kWh, 1996 $)	7.91	8.20	6.99	6.55	7.03
COE (¢/kWh Constant 1990 $)	6.10	6.31	5.39	5.11	5.43

SOURCE: National Renewable Energy Laboratory, 1997, Cost and Performance Analysis of Biomass-based Integrated Gasification Combined – Cycle Power System.

The National Renewable Energy Laboratory[59] conducted another study on the renewable technology cost trends in October 2002. The results of this study show that the levelized cost of electricity generation (in 2000 constant dollars) from renewable technologies has steadily declined in the past quarter century. The cost of electricity generation (COE) from biomass gasification technology has declined from about 12 cents per KWh in 1980 to slightly above 6 cents per KWh in year 2000. The lower cost resulted from technology improvements and improvements in feedstock handling, gas processing clean up and overall plant design optimization.

This study also reveals that the cost of electricity generation from biomass gasification technology is higher than other renewable electricity technologies. Figure 6.4 shows the historical COE trends and projections through 2020 for renewable electricity technologies.

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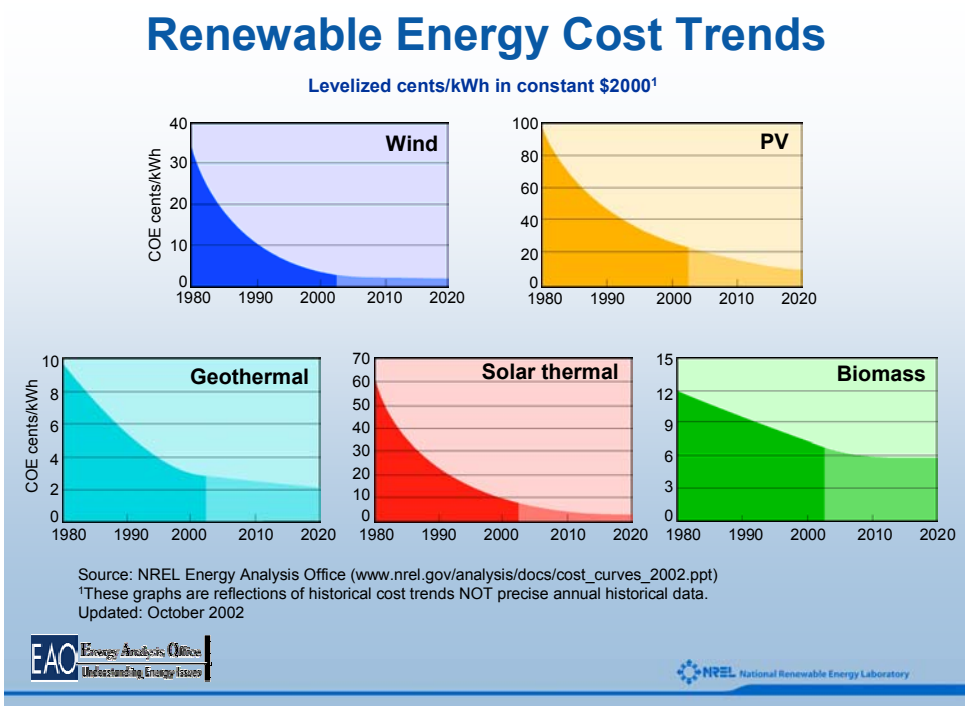
Figure 6.4
levelized Renewable Energy Cost- cents/kWh in Constant 2000 USD



59 NREL Energy Analysis Office, http://www.nrel.gov/analysis/docs/cost_curves_2002.ppt#2

The Electricity Market Module (EMM) of The National Energy Modeling System (NEMS) determines the most economical way to supply electricity, within environmental and operational constraints. The EMM composed of four sub-models of electricity capacity planning, electricity fuel dispatching, load and demand-side management, and finance and pricing.

The cost and performance characteristics of biomass integrated gasification combine cycle that is input to the electricity capacity planning sub-models for biomass gasification technology[60] is summarized in table 6.5.

Table 6.6
Cost and Performance Characteristics of Biomass IGCC
(2003 USD)

Technology	IGCC
Capacity (MW)	80
Heat rate (Btu/kWh)	8,911
Overnight Cost[1] (2003 $/kW)	1,757
Variable O&M (2003 mills[2]/kWh)	2.96
Fixed O&M (2003 $/KW)	47.18
Lead times (Years)	4

SOURCE: Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38
[1] Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.
[2]mills = 1/10 of one cent.

TRI – State Generation and Transmission Association [61] purchase renewable and non-renewable generated power from the producers. The TRI has presented the range of generated costs for both renewable and nonrenewable resources. TRI expects the renewable resources will become less costly and more widely available. Table 6.6 shows a summary of renewable and non renewable electricity costs

Table 6.7
Cost and Operating Availability of Electricity generation

Wholesale	Coal	Wind	S-Hydro	Biomass	Solar
COE (¢/kWh)	2-5	3-7	2-5	3-5	21-25
O-Availability	85-95%	30%	25-50%	0-60%	25

60 Energy Information Administration (EIA), Assumptions to the Annual Energy Outlook 2005 with Projection to 2025. http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf

61 TRI- STATE G&T Association, http://www.tristategt.org/greenpower/cost.cfm

CHAPTER 7
GAS TURBINE POWER PLANTS

7.1 Overview

Cogeneration systems can be classified by thermodynamic cycle or by type of prime mover. The latter, more prevalent method, usually presumes particular fuels as inputs.

Natural gas is often considered the premium fuel for power generation because it is clean, easy to transport and easy to feed into the combustion process. Natural gas can be used as fuel for a variety of single and cogeneration technologies.

This chapter will provide a brief description of gas turbines, their performance and capital and operating costs.

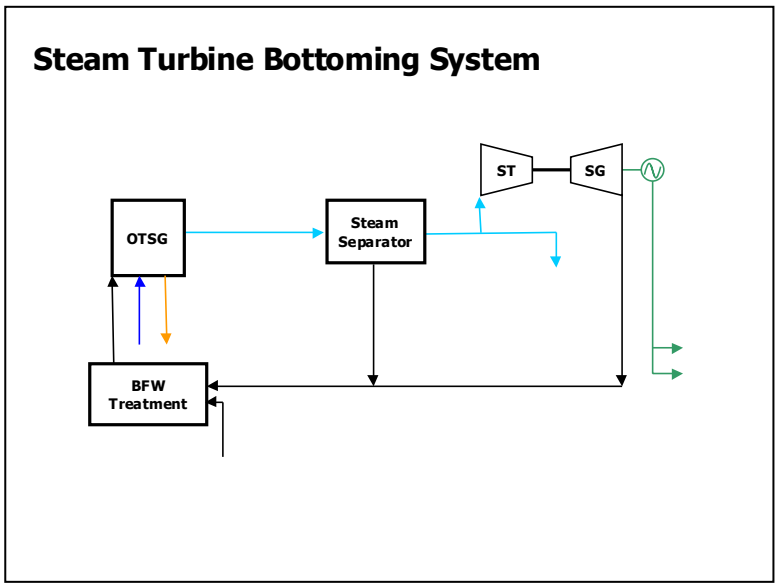
7.1.1 Steam Turbine Systems

Steam turbine systems are the most common cogeneration systems and range from 500 kW to 80 MW. Steam is generated in a high-pressure steam boiler. The steam expands through a steam turbine to produce mechanical energy, which drives an electric generator. The expanded steam is then cooled and condensed in a heat exchanger (condenser or a process cooler) which recovers the heat. The temperature in the condenser determines the pressure at which the steam is expanded. Lower temperatures mean extensive expansion and high electrical efficiency.

In a bottoming system, high temperature thermal energy is produced first. Heat is recovered from the hot exhaust waste stream and transferred to a fluid which is vaporized, driving a turbine to produce electricity. Steam turbine systems usually produce significantly more heat than electricity per unit of fuel consumed. The lower the quality of heat required, the greater the amount of electricity generated per unit of fuel.

In a back-pressure steam turbine system, all of the steam expanded is used for heat application. The extraction-condensing steam turbine system is a hybrid between a fully condensing and a back-pressure system. This system gives a high degree of flexibility.

Figure 7.1
Steam Turbine Bottoming System



Variations of the basic Rankine cycle include reheat and regeneration. In a Rankine cycle with reheat, high-pressure vapour from the first steam turbine is reheated in the boiler before passing through a second, lower pressure turbine. In a regenerative Rankine cycle, the working fluid that emerges from the condenser as a subcooled liquid is heated by steam tapped from the hot portion of the cycle. This increases the average temperature of heat addition, increasing the thermodynamic efficiency of the cycle.

7.1.2 Gas Turbine Systems

The most common cogeneration mode is a topping gas turbine system, which produces electricity first and the remaining thermal energy is used for purposes such as industrial processes, water and space heating.

Gas turbines are the most common prime movers in recent large cogeneration systems and follow the Brayton process. These systems include gas turbines and electrical generators, with exhaust gases from the gas turbines typically fed to heat recovery steam generators (HRSGs). They range in electricity output from 250 kW to 200 MW. In general, they produce more electricity per unit of fuel than steam turbine systems and have an average heat-to-power ratio of 2:1. Supplemental heating through secondary firing of exhaust gases can increase this ratio to 5:1. Steam injection increases electrical output by 15 percent.

Gas turbines consist of a compressor, combustion chamber and an expander. Air is compressed in the compressor. Fuel is burned with the compressed air in the combustion chamber. The high

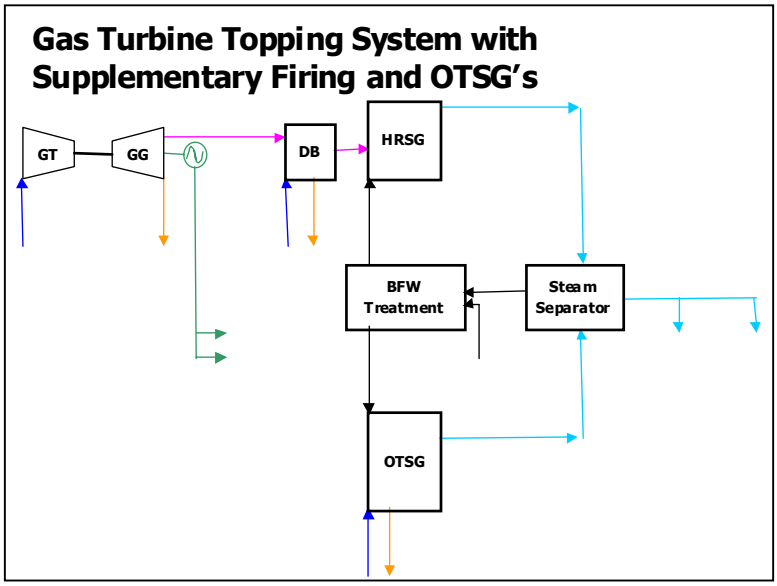
temperature combustion gas/air mixture expands in the turbine, driving a generator and producing electricity. Exhaust gases exit the turbine at temperatures of 350 to 600 ºC.

There are two types of gas turbines on the market: industrial gas turbines and aero-derivative gas turbines. Industrial gas turbines are designed for power generation and mechanical drive applications. Aero-derivative gas turbines are modified gas generators from aero engines, which are connected to an industrial turbine, with a generator.

Efficiencies with heat recovery range from 25 percent to 40 percent and the overall efficiency, after heat recovery, could reach 80 to 90 percent.

Microturbines are small combustion turbines that produce between 25 kW and 500 kW of power.

Figure 7.2
Sample Gas Turbine Topping Cycle Layout



7.1.3 Reciprocating Engine Systems

A reciprocating engine, also often known as a piston engine, is an engine that utilizes one or more pistons in order to convert pressure into a rotating motion (e.g. automobile engine). The burning fuel such as gasoline, diesel fuel, oil or natural gas provide pressure. Each piston is located inside a cylinder, into which a fuel and air mixture is introduced, and then ignited. The now hot gases expand, pushing the piston away. The linear movement of the piston is converted to a circular movement via a connecting rod and a crankshaft.

The more cylinders a piston engine has, the more power it is capable of producing. These engines are known collectively as internal-combustion engines[62], although internal-combustion

62 An internal combustion engine is an engine that is powered by the expansion of hot combustion products of fuel directly acting within an engine.

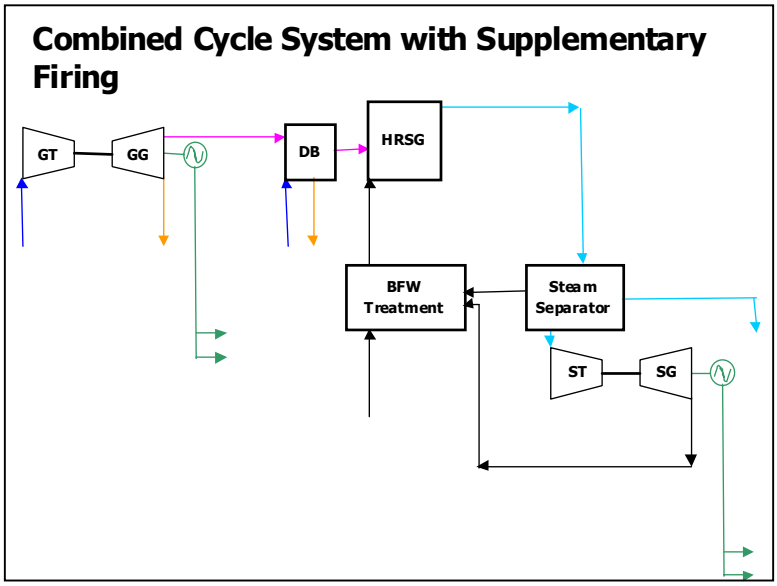
engines do not necessarily contain pistons. In most applications of steam power, the piston engine has been replaced by the more efficient turbine.

Reciprocating engine systems range in electricity output from 20 kW to 50 MW. The heat-to-power ratio ranges from 0.5:1 to 2.5:1. Supplementary firing can increase thermal output. Exhaust gases are of high temperature, up to 400 ºC, but the engine cooling system provides only low-grade heat below 90 ºC. These systems produce more electrical energy per unit of fuel, (35 percent to 53 percent) than either steam or gas turbines.

7.1.4 Combined Cycle Systems

Combined cycle systems use both gas turbines and a steam turbines for electricity generation. The hot exhaust gases from the gas turbine produce steam for the steam turbine. The thermal output remaining in the steam exhausted from the steam turbine goes to process applications. These systems increase electric power output at the expense of recoverable heat.

Figure 7.3
Sample Combined Cycle Layout



7.2 Performance Characteristics

The key advantage of cogeneration is its efficiency in generating electricity and thermal energy. The total fuel consumed by a cogeneration system is less than the total fuel consumed by two separate systems i.e. one producing electricity and one producing thermal energy.

The knowledge of electric efficiency of cogeneration systems and the heating value of the chosen input fuel determines the amount of fuel required for electricity generation. Higher amounts of fuel are needed when fuels with lower heating values are used for electricity generation.

Heating values of fuels (thermal efficiency) express the amount of energy which is released on combustion of a given quantity of fuel. Heating values are typically expressed in Btu per fuel unit. Two types of high heating value (HHV)[63] and low heating value (LHV)[64] are used for measuring the energy content of a fuel.

Since the fuel energy appears in the denominator of the expression for efficiency, using the lower heating value will make systems appear to be about 11 percent more efficient than using the HHV. For example, if the efficiency based on the higher heating value is 35 percent, the efficiency based on the lower heating value will be 35 percent * 1.11 = 38.9 percent.

The heating value of natural gas is 1,000 Btu per cubic foot. The level of emissions produced from burning natural gas is substantially lower than the level from burning coal. Natural gas can be gasified,[65] but this process is not economically viable and cogeneration cannot benefit economically from this option.

Thermal efficiency is a power source that transforms the potential heat of its fuel into work or output (heat energy).

$$E_{th} = Q_{th} / Q_{fuel}$$

Electrical efficiency is the ratio of useful electrical power output to the total electrical power input (heat resource).

$$E_e = Q_e / Q_{fuel}$$

The electrical efficiency of cogeneration depends on the selected technologies, where the range of efficiency varies from 14 percent to 70 percent.

Overall efficiency is the sum of the heat and electricity generation energy values to the total heat energy content in the fuel burned.[66]. One KWH of electricity equals 3,413 BTU[67]. Overall cogeneration efficiencies range from 65 percent to 85 percent.

$$E_{tot} = (Q_{th} + Q_e) / Q_{fuel}$$

The heat-to-power ratio is the ratio of useful thermal energy available to the amount of electricity generated. It is expressed as kW_{th}:kW_e and ranges from 0.5:1 to 10:1.

63 The high heating value (HHV) is a measure of the total heat that can be recovered from the combustion of a fuel, including the heat that is derived from condensing the water vapor. The water vapor is an inevitable product of the reaction of hydrogen in the fuel that is combined with oxygen

64 The low heating value (LHV) excludes the heat which is derived from condensing the water.

65 Production of syngas from natural gas feedstock is $CH4 + H2O \rightarrow CO + 3\ H2$

66 One British thermal unit (Btu) is the amount of energy in the form of heat which will raise the temperature of one pound of water one degree Fahrenheit

67 1 Joules = 1 Watt per second , 1 watt per hour = 3600 Watt per second = 3.6 KJ

1 KWh = 1000 * 3.6 KJ = 3.6 MJ = 3.6 * 10 6 * J, 1BTU = 1055 J

1KWh = (3.6 * 10 6 * J) / 1055 J = 3,413 BTU

European engineering practice favors the use of HHV while the Americans prefer the LHV. For hydrocarbon fuels the LHV is approximately 10 percent lower than the HHV.

The European Association and UNESCAP report a summary of cogeneration efficiency and heat-to-power ratios for alternative technologies as follows:

Table 7.1
Cogeneration Efficiency and Heat-to-Power Ratios and Thermal Quality

Cogeneration system	Electrical energy output (% of fuel input)	Overall efficiency (LHV)	Heat-to-power ratio
Back-pressure steam turbine	14-28	84%-92%	4.0-14.3
Condensing steam turbine	22-40	60%-80%	2.0-10.0
Gas turbine	24-42	70%-85%	1.3-2.0
Reciprocating engine	33-53	75%-85%	0.5-2.5
Combined cycle	34-55	69%-83%	1.0-1.7
Micro turbines	15-33	60%-75%	1.3-2.0

SOURCE: The European Association for the Promotion of cogeneration and the United Nations Economic and Social Commission for Asia and the Pacific (UNESCAP).[68]
Note: Micro turbines are small combustion-turbine generators that were developed on the basis of the turbo-charges technology used in airplanes. The capacity range is from 30 KW to 400 KW.

One factor that affects cogeneration system economics is system availability and reliability. Electricity is not produced during hours when the cogeneration system is down. Not only must electricity be purchased, but outages can also affect costs of standby service.

Availability is the percentage of time the plant is available for generation taking into account scheduled and unscheduled outages. Reliability is the probability that a device, system, or process will perform its prescribed duty without failure for a given time when operated correctly in a specified environment.

The Canadian Electricity Association (CEA)69 keeps operating statistics on electricity generating units operated in Canada by electric utilities and by Alcan Primary Metal Group. These statistics permit a comparison of reliability and chosen mode of operation (base load, intermediate, peaking) among the different technologies and fuels.

68 www.euractiv.com

69 Canadian Electricity Association, 2003 Annual Report, Equipment Reliability Information System.

Table 7.2 shows the values of key operating statistics for steam and combustion gas turbines in 2003, and their average for the period 1999-2003. The definition of operating factor (OP factor), available but not operating factor (ABNOF), forced outage rate (FOR), and derating adjusted forced outage probability (DAUFOP) are defined in Chapter 1.

Table 7.2
Operating Characteristics of Canadian Steam and Combustion Gas Turbines

	Period	OP Factor (%)	ABNOF (%)	FOR (%)	DUFOP (%)
Steam Turbine	2003	12.96	71.52	18.16	10.45
	1999-2003	46.06	33.91	15.31	13.39
Combustion Turbine	2003	13.19	73.97	22.96	8.72
	1999-2003	18.68	69.80	21.06	9.20

SOURCE: Canadian Electricity Association, 2003 Generation Equipment Status Annual Report, tables 6.2.13 &14 and tables 6.3.1 &2

The values of "OP factor" and "ABNOF" determine the availability of the operation. Over the five-year period 1999-2003 steam gas turbine units in Canada were "available but not operating, ABNOF" 33.91 per cent of the time, compared to 69.80 percent for combustion turbines.

The CEA also reports that over the same five-year period the probability that a unit would be unavailable if needed ("DAUFOP") was 13.39 percent for all steam gas turbines compared to 9.20 per cent for combustion turbines.

CERI has concluded that

- If OP FACTOR is high and ABNOF is low then the unit could be consider for the base-load.
- If OP factor is low and ABNOF is high than the unit could be consider for peaking-load.
- Any number between the above two factors could represent the intermittent-load.

The value of FOR and DAUFOP determine the reliability of the operation. Closer the values FOR and DAUFOP to zero indicates more reliability of the units.

Table 7.2 indicates that over the period 1999 to 2003, the Canadian combustion gas turbines operated for the peaking – load and they were more reliable than steam turbines.

7.3 Capital and Operating Costs

Natural gas has not been the fuel of choice for large steam cycle plants due to the price and availability of natural gas.

Although the price of natural gas is substantially higher than coal, the effective cost of natural gas as a fuel can be reduced if a cogeneration unit is equipped with a dual fuel boiler and the owner of the facility pays for the interruptible rather than firm price of natural gas. Economic justification of cogeneration investment requires both the price and supply of natural gas to be taken into account over the life of investment decision.

The capital cost of the gas turbine power plants depends on the size of the plant and the selected technology of turbine systems. The main component of generation costs are the installed cost of the equipment, fuel costs, and non-fuel operation and maintenance (O&M) costs.

In 2003 the US Congressional Budget office (COB) estimated the costs of alternative technologies. For estimating long-run average costs of generation, the CBO assumed for each technology an installed capacity, a rate of utilization (the percentage of time that the unit typically operates) and in some cases a geographic location that would be suitable for serving the electricity needs of individual customers.

The CBO assumed that all fossil-fuel systems have a capacity utilization rate of 90 percent (termed "base load" operation). Other CBO assumptions include fuel costs, which were calculated on the basis of national average prices for natural gas delivered to commercial customers in 2000. Future costs and output flows were discounted at an annual rate of 7 percent to get levelized costs.

The utility charges, for purchasing the generated electricity from the distributed generation or from connecting to the grid, were not included in the costs. However, for the grid power, transmission and distribution expenses would add an estimated 2.4 cents per kilowatt-hour, on average, to the marginal cost of delivered power.

In this study the CBO has not been take into account the effects of tax credits or other direct subsidies for specific technologies. In the USA, at the federal level, the Energy Policy Act of 1992 provides tax credits for certain investments in solar, wind, and biomass-fuelled electricity generation.

Table 7.3 shows the component costs for gas turbine technologies. Micro turbines have the highest capital costs and those technologies that produce “power only” have the highest fuel cost per kilowatt hour.

In general, the most efficient plants are technologies that produce combined heat and power (CHP). Technologies that produce “power only” are less efficient than the CHP technologies.

The cost per kilowatt hour of power for a combined-cycle system and combustion gas turbine, producing steam and power, have the lowest levelized costs of the technologies.

Table 7.3
Cost of Electricity Generation – Gas Turbine Technologies
(2000 USD)

	Capacity (kW)	Capital Cost ($/kW)	Fuel Cost ($/kWh)	O&M Cost ($/kWh)	Service Life (Years)	Heat Rate (Btu/kWh)	Levelized Electricity cost ¢/kWh
Microturbine-Power only	100	1,485	0.075	0.015	12.5	13,127	11.0
Microturbine--CHP	100	1,765	0.035	0.015	12.5	6,166	7.5
Gas ICE--Power Only	100	1,030	0.067	0.018	12.5	11,780	10.0
Gas ICE--CHP	100	1,491	0.027	0.018	12.5	4,717	7.0
Combustion Gas Turbine-Power Only	10,000	715	0.067	0.006	20	11,765	8.0
Combustion Gas Turbine-CHP	10,000	921	0.032	0.006	20	5,562	4.8
Combined-Cycle System	100,000	690	0.032	0.006	20	5,642	4.7

SOURCE: Congressional Budget Office based on data from the Department of Energy's National Renewable Energy Laboratory and Energy Information Administration.
NOTE: Btu = British thermal unit; CHP = combined heat and power; ICE = internal combustion engine.

The OECD has recently published the findings of an empirical study[70] on the levelized cost of electricity generation. The study applied field surveys and covered a multitude of electricity generating technologies in a few countries including Canada and the USA.

The OECD study applied generic assumptions in order to derive its calculations. Salient assumptions include: economic lifetime (40) years, average load factor for base-load plants (85 percent) and discount rates (5 percent and 10 percent) and base year is July 2003. The electricity generation costs are busbar costs, at the station, and therefore do not include transmission and distribution or environmental costs. Table 7.4 shows the component and levelized cost of electricity generation for gas fired plant and CCGT.

Table 7.4
Levelized Cost of Electricity Generation – Gas Fired Plants and CCGT
(2003 USD/MWh)

Technologies - Country/plant type	Dis. Rate	Net Capacity Mwe	Overn Const Cost – Musd	Lev. Capital Cost	Lev. O&M	Lev. Fuel Cost	Lev. Electricity Cost
USA-G1:CT/SCR,FF	5%	230	106	3.6	1.9	41.2	46.7
USA-G1:CT/SCR,FF	10%	230	106	6.4	1.9	40.8	49
CAN-G:CCGT/LNB	5%	580	342	5.3	2.6	32.1	40
CAN-G:CCGT/LNB	10%	580	342	8.9	2.6	32.1	43.6
USA-G2:CCGT/SCR,FF	5%	400	244	4.9	3.5	30.9	39.3
USA-G2:CCGT/SCR,FF	10%	400	244	8.7	3.5	30.6	42.8
USA-CHP1:Gas	5%	40	27.2	5.7	1	43.8	29.4
USA-CHP1:Gas	10%	40	27.2	9.9	1	43.4	29.4
USA-CHP2:Gas engine	5%	3	2.61	7.2	2.1	43.2	29.4
USA-CHP2:Gas engine	10%	3	2.61	12.7	2.1	42.8	29.4

SOURCE: IEA, Projected Cost of Generating Electricity 2005 Update, OECD, Paris, France.
NOTES: **CHP**, Combined heat and power; **CCGT**, Combined cycle gas turbine; **CT**, Combustion Turbine; **FF,** Fabric filters; **LNB,** Low NO_x burners; **SCR,** Selective catalytic reduction (de NO_x)

The Electricity Market Module (EMM) of The National Energy Modeling System (NEMS) determines the most economical way to supply electricity, within environmental and operational constraints. The EMM composed of four sub-models of electricity capacity planning, electricity fuel dispatching, load and demand-side management, and finance and pricing.

The cost and performance characteristics of gas turbine technologies[71] that are input to the electricity capacity planning sub-models are shown in table 7.5.

70 OECD: Projected Costs of Generating Electricity: 2005 Updates.

71 Energy Information Administration (EIA), Assumptions to the Annual Energy Outlook 2005 with Projection to 2025.
http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf

Table 7.5
Cost and Performance Characteristics of Gas Turbine Technologies
(2003 USD)

Techology	Capacity (MW)	Heat rate (Btu/kWh)	Total Overnight Cost in 2004[1] (2003 $/kW)	Variable O&M ($2003 mills[2]/kWh)	Fixed O&M[3] ($2003/Kw)	Leadtimes (Years)	Online Year[4]
Conv. Gas/Oil Comb Cycle	250	7,196	567	1.83	11.04	3	2007
Adv Gas/Oil Comb Cycle (CC)	400	6,752	558	1.77	10.35	3	2007
ADV CC with Carbon Sequestration	400	8,613	1,114	2.60	17.60	3	2010
Conv Combustion Turbine[3]	160	10,817	395	3.16	10.72	2	2006
Adv Combustion Turbine	230	9,183	374	2.80	9.31	2	2006

SOURCE: Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38[1]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.
[2]mills = 1/10 of one cent.
[3]Combustion turbine unites can be built by the model prior to 2006 if necessary to meet a given region's reserve margin.
[4]Online year represents the first year that a new unit could be completed, given an order date of 2004, pg. 67.

CHAPTER 8
SOLAR AND FUEL CELLS

8.1 Overview

Solar, a renewable source of electricity generation; and fuel cells, which promise both lower emissions and a higher efficiency of conversion to electricity than conventional fossil fuel technologies, have recently become of interest to policy makers in the context of rising prices for primary energy. This chapter will provide a brief description of solar and fuel cell technologies, and discuss their performance and associated costs.

8.2 Solar Photovoltaic and Solar Thermal Electricity Conversion

Solar technologies for generating electricity are of two general types: photovoltaic (PV), in which sunlight is converted directly into electricity, depicted in Figure 8.1; and solar thermal electricity conversion (STEC), in which sunlight is converted first into heat and then into electricity, depicted in Figure 8.2.

Photovoltaic technology uses solid-state semiconductor devices to convert sunlight into direct-current electricity. Although the underlying science was discovered by Becquerel in the ninteenth century, significant progress in commercialization became possible with Bell Labs' invention of the silicon solar cell in 1954 and its early use in powering earth satellites. In the late 1970s solar thermal electricity production was born in the desert of southern California. Concentrated sunlight heated a fluid creating steam, which in turn drove a turbine generator.

Solar technologies have found a niche in locations beyond the reach of electricity transmission and distribution systems, such as space travel and isolated communities; and in applications such as calculators and certain telecommunications equipment that require very modest amounts of power. Penetration of other markets that would appear to offer more potential has been slow. Typically solar power would not be available to meet Ontario's annual peak that occurs near 6 pm on a winter weekday, as the sun would not be shining. It would, however, be very much available during the annual peak of a year such as 2002 or 2005, during a summer heat wave. Solar shares with wind the property of intermittency. It has to be taken when available and is therefore not dispatchable.

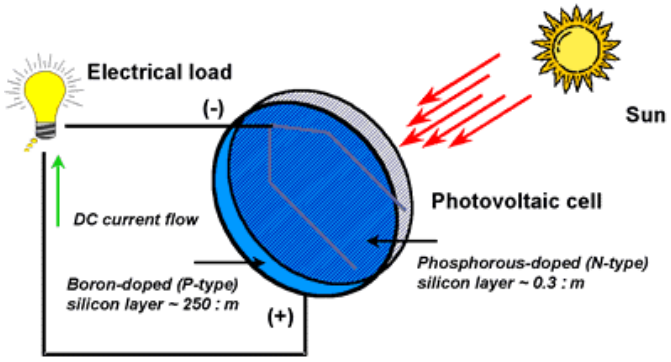
8.2.1 Performance Characteristics

These solar technologies in some circumstances lend themselves to use by homeowners and by business establishments whose main purpose is something other than the generation of electricity for sale. Such applications, which may produce heat as well as electricity in seasonally varying proportions, are beyond the scope of this report, which concerns itself with facilities built for the purpose of supplying electricity to the Ontario grid. The following considerations,

identified by Resource Dynamics Corporation[72], give an indication of the possible scope of an investigation into prospects for generation of this sort:

- Allowing customers to continuously generate their own electricity, with or without grid backup,
- Permitting customers to generate power while serving their thermal and/or cooling loads,
- Generating a portion of electricity onsite to reduce the amount of electricity purchased during peak price periods,
- Licensing customers to sell excess generation back onto the grid when their own demand is low, especially during peak pricing periods,
- Using standby or emergency power to backup grid based power,
- Improving customer power quality and reliability,
- Serving niche applications, such as "green" power or remote power,
- Meeting continuous power, premium power, or cogeneration needs of the residential market.

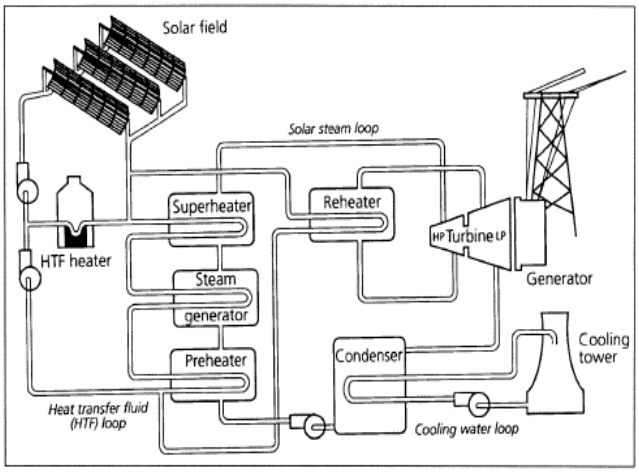
Figure 8.1
Photovoltaic Cell



SOURCE: Florida Solar Energy Centre, University of Central Florida, available on the Internet at www.fsec.ucf.edu/pvt/pvbasics

72 SOURCE: www.distributed-generation.com/applications.htm, a website maintained by Resource Dynamics Corporation.

Figure 8.2
Solar Thermal Electric Technology



SOURCE: Kearney & Associates, "Solar Electric Generating System (SEGS) Assessment for Hawaii", 1992, available on the Internet at www.state.hi.us/dbedt/ert/segs92.pdf.

Dallas Burtraw et al.[73] found that the cost overruns typical of technologies in their early stages of development have not been characteristic of solar or indeed of renewable technologies in general:

> Our findings document a significant difference between the success of renewable technologies in penetrating the U.S. electricity generation market and in meeting cost-related goals, when compared with historic projections. In general, renewable technologies have failed to meet expectations with respect to market penetration. They have succeeded, however, in meeting expectations with respect to their cost. For every technology analyzed, successive generations of projections of what they would cost in the future have either agreed with previous projections or been more optimistic (predicted even lower costs). This success is remarkable, given that renewable technologies have not significantly penetrated the market, nor have they attracted large-scale investment and production that can contribute to technological development or economies of scale in production, as many analysts anticipated when forming their cost projections.

The OECD has recently published the findings of an assessment[74] of the levelized cost of electricity generation. The study applied field surveys and covered a multitude of electricity generating technologies in a few countries including Canada and the USA.

The OECD study applied generic assumptions in order to derive its calculations. Salient assumptions include: economic lifetime of 40 years, average load factor for base-load plants of

73 Burtraw, D. et al, "Renewable Energy: Winner, Loser or Innocent Victim?" Resources, Spring 1999, pp. 9-13, available on the internet at www.rff.org/Documents/RFF-Resources-135-renewenergy.pdf.

74 OECD: Projected Costs of Generating Electricity: 2005 Update.

85 percent, discount rates of 5 percent and 10 percent, and (July) 2003 base year. The electricity generation costs are busbar costs, and therefore do not include transmission, distribution or environmental costs. Table 8.1 shows the levelized cost of electricity generation by component for solar technologies. The study did not divulge the assumed capacity factor for solar technologies, nor is it entirely clear that a forty-year life was assumed. (An operating life of 25 or 30 years is a more common assumption for solar technologies.)

Table 8.1
Levelized Cost of Electricity Generation from Solar
(2003 USD/MWh)

	Discount Rate	Net Capacity MW	Overnight Const Cost – millions of US$	Levelized Capital Cost	Levelized O&M Cost	Levelized Electricity Cost
USA Solar thermal parabolic	5%	100	277.5	127.4	38.1	165.5
USA Solar thermal parabolic	10%	100	277.5	231.4	38.1	269.4
USA Solar Photovoltaic	5%	5	20.8	115.8	4.8	120.6
USA Solar Photovoltaic	10%	5	20.8	204.4	4.8	209.1

SOURCE: OECD (NEA/IEA), Projected Cost of Generating Electricity: 2005 Update, Paris, France.

The Electricity Market Module (EMM) of The National Energy Modeling System (NEMS) assesses the most economical way to supply electricity, within environmental and operational constraints. The EMM consists of four sub-models: electricity capacity planning, electricity fuel dispatching, load and demand-side management, and finance and pricing.

The costs and performance characteristics of solar according to NEMS[75] are summarized in Table 8.2. Note that these costs are about ten per cent higher than those reported in the OECD document, and that there was no NEMS calculation of levelized costs.

In the interests of transparency CERI has taken these overnight construction costs[76] together with fixed annual O&M costs for STEC and PV as reported by NEMS and calculated levelized costs, shown in Table 8.2, at a 5 percent discount rate for 25-year and 30-year economic lives, applying capacity factors of 15 percent and 25 percent. This range for capacity factors can be justied on the following basis.

As Sandia National Laboratories[77] notes, "Without energy storage, the annual capacity factor of any solar technology is generally limited to about 25 percent." The Solar Electric Power Association[78] used capacity factors varying from 15 percent for northeastern US states to 20

75 Energy Information Administration (EIA), Assumptions to the Annual Energy Outlook 2005 with Projection to 2025. http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf

76 For example overnight cost in table 8.3 = 4,476 * 5,000 = 22.3 millions US$

77 Sandia National Laboratories, National Solar Thermal Test Facility: Desirable Features of Power Towers for Utilities, p. 1, available on the Internet at www.sandia.gov/Renewable_Energy/Solarthermal/NSTTF/feature/htm.

78 Solar Electric Power Association, "Projecting the Impact of State Portfolio Standards on Solar Installations, prepared for the California Energy commission, and available on the Internet at www.solarelctricpower.org/ewebeditpro/items/064F5151.pdf.

percent for Arizona in a study of photovoltaic costs by state. For California, it assumed 18 percent.

Table 8.2
Costs and Performance Characteristics of Solar Technologies
(2003 USD)

Technology	Solar Thermal	Photovoltaic
Capacity (MW)	100	5
Heat rate (Btu/kWh)	10,280	10,280
Overnight Cost[1] (2003 $/kW)	2,960	4,467
Variable O&M (2003 mills[2]/kWh)	0.00	0.00
Fixed O&M (2003 $/KW)	50.23	10.34
Lead times (Years)	3	2
Online[3]	2007	2006

SOURCE: Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38
[1] Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.
[2]mills = 1/10 of one cent.
[3]Online year represents the first year that a new unit could be completed, given an order date of 2004.

It turns out that levelized costs for solar technologies are highly sensitive to capacity factor and less sensitive to assumed economic life. It was also found that levelized costs are quite sensitive to discount rates. At a 10 percent discount rate, levelized costs as calculated were about 50 percent higher than the corresponding figures in the final column of Table 8.3. Photovoltaic, being more capital-intensive than STEC, is more sensitive to choice of discount rate.

Table 8.3
Levelized Cost of Electricity Generation from Solar
(2003 USD/MWh)

	Capacity Factor	Operating Life	Net Capacity MW	Overnight Const Cost – millions of US$	Levelized Capital Cost	Levelized O&M Cost	Levelized Electricity Cost
USA Solar thermal	15%	25 years	100	296	92.8	84.6	177.4
parabolic	25%	25 years	100	296	55.7	50.8	106.5
USA Solar thermal	15%	30 years	100	296	85.1	80.8	165.8
parabolic	25%	30 years	100	296	51.0	48.5	99.5
USA Solar Photovoltaic	15%	25 years	5	22.3	214.1	7.9	222.0
	25%	25 years	5	22.3	128.4	4.7	133.2
USA Solar Photovoltaic	15%	30 years	5	22.3	196.3	7.9	204.1
	25%	30 years	5	22.3	117.8	4.7	122.5

SOURCES: United States Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38; Canadian Energy Research Institute.
NOTE: 5 percent discount rate is applied for estimation of levelized cost.

8.3 Fuel Cells

A fuel cell consists of two electrodes sandwiched around an electrolyte. Oxygen passes over one electrode and hydrogen over the other, generating electricity, water and heat.

Hydrogen fuel is fed into the anode (the negative electrode) of the fuel cell. Oxygen (or air) enters the fuel cell through the cathode (the positive electrode). Encouraged by a catalyst the hydrogen atom splits into a proton and an electron, which take different paths to the cathode. The proton passes through the electrolyte[79]. The electrons create a separate current that can be utilized before they return to the cathode, to be reunited with the hydrogen and oxygen in a molecule of water. Figure 8.3 shows a schematic diagram of Proton Exchange Membrane (PEM)[80]l. The PEM is a substance that allows hydrogen and oxygen to pass through fuel cell.

Three main components of a fuel cell system are the hydrogen fuel reformer, fuel cell stack and the power conditioner.

- A "fuel reformer" utilizes the hydrogen from any hydrocarbon fuels such as natural gas, propane and methanol and feed to the fuel cell. The produced mixed hydrogen and other gases should be purified. This process lowers the efficiency of the fuel cell. However, Since the fuel cell relies on chemistry (converts chemical energy to electrical energy) and not combustion, emissions is smaller than combustion fuel processes.

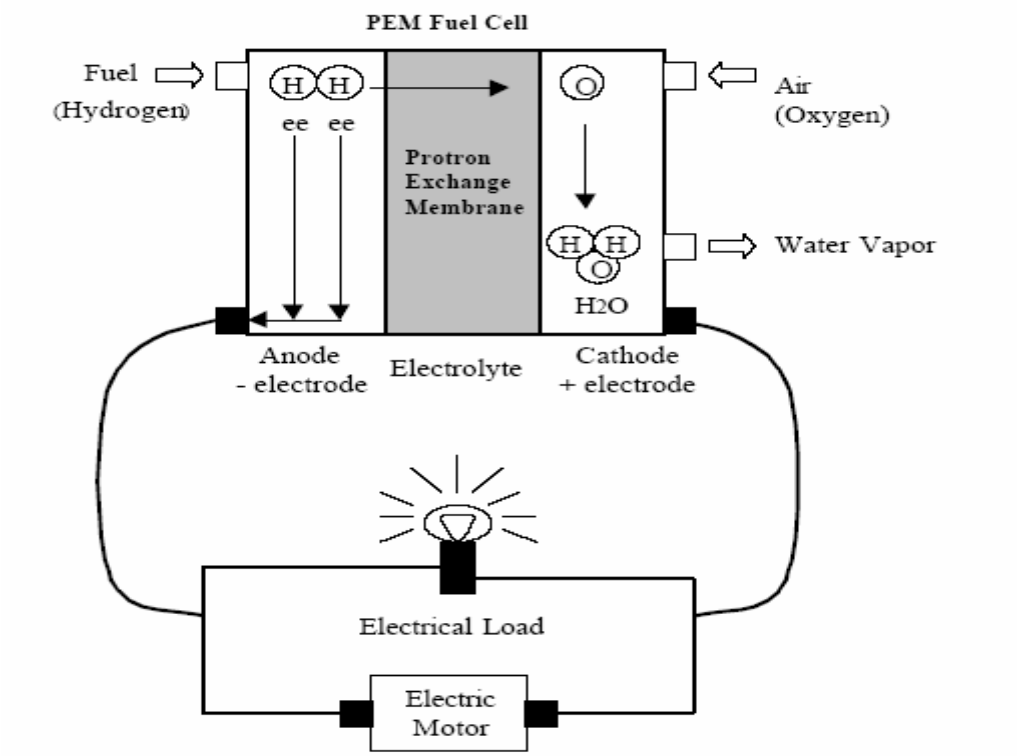
- The fuel cell stack converts the hydrogen and oxygen from the air into electricity, water vapor and heat. Furthermore, a single fuel cell produces only about 0.7 volts electricity. To get this voltage up to a reasonable level, many separate fuel cells must be combined to form a fuel-cell stack.

- The power conditioner then converts the DC current from the stack into the AC current for using the electricity for the appliances.

79 electrolyte – in a Proton Exchange Fuel Cell this material is between the Cathode and the Anode and is primarily made of Nafion which is a Dupont Polymer

80 http://www.netl.doe.gov/coolscience/teacher/lesson-plans/lesson6.pdf

Figure 8.3
PEM Fuel Cell



There are several different types of fuel cells, each using a different chemistry. Fuel cells are usually classified by the type of electrolyte they use. Some types of fuel cells work well for use in stationary power generation plants. Others may be useful for small portable applications or for powering cars.

Alkaline fuel cell (AFC): This is one of the oldest designs. The AFC is very susceptible to contamination, so it requires pure hydrogen and oxygen.

Phosphoric-acid fuel cell (PAFC): The phosphoric-acid fuel cell has potential for use in small stationary power-generation systems. It operates at a higher temperature than PEM fuel cells.

Solid oxide fuel cell (SOFC): These fuel cells are best suited for large-scale stationary power generators. This type of fuel cell operates at very high temperatures (around 1,832 F, 1,000 C). This high temperature makes reliability a problem, but it also has an advantage: The steam produced by the fuel cell can be channeled into turbines to generate more electricity. This improves the overall efficiency of the system.

Molten carbonate fuel cell (MCFC): These fuel cells are also best suited for large stationary power generators. They operate at 600^0 C, so they also generate steam that can be used to generate more power.

8.3.1 Performance characteristics

Fuel cells compete with many other types of energy conversion devices, including the gas turbines in the power generation, the gasoline engine in the automobile and the battery in the laptop. Combustion engines like the turbine and the gasoline engine burn fuels and use the pressure created by the expansion of the gases to do mechanical work. Batteries convert chemical energy back into electrical energy when needed. Fuel cells perform both tasks more efficiently

Large fuel cells are able to generate electricity more efficiently than combustion power plants. The fuel-cell technologies being developed for these power plants generate electricity directly from hydrogen in the fuel cell, but will also use the heat and water produced in the cell to power steam turbines and generate even more electricity.

Fuel cells are ideal for power generation, either connected to the electric grid to provide supplemental power and backup assurance for critical areas, or installed as a grid-independent generator for on-site service in areas that are inaccessible by power lines. Since fuel cells operate silently, they reduce noise pollution as well as air pollution and the waste heat from a fuel cell can be used to provide hot water or space heating for a home

Modular installation (the installation of several identical units to provide a desired quantity of electricity) provides extremely high reliability up to 99 percent.

If the fuel cell is powered with pure hydrogen, it has the potential to be up to 80-percent efficient. That is, it converts 80 percent of the energy content of the hydrogen into electrical energy. Adding a reformer to convert for example methanol to hydrogen, the overall efficiency drops to about 30 to 40 percent[81].

8.3.2 Capital Cost and Operating Costs

Fuel cells costs per installed kilowatt are still high relative to those of conventional technology, commercially available fuel fuel cells currently suit only very specicilized applications.

A study by Arthur D. Little, Inc., predicted that when fuel cell costs drop below $1,500 per kilowatt, they will achieve market penetration nationwide[82].

The OECD has recently published the findings of an empirical study[83] on the levelized cost of electricity generation. The study applied field surveys and covered a multitude of electricity generating technologies in a few countries including Canada and the USA.

The OECD study applied generic assumptions in order to derive its calculations. Salient assumptions include: economic lifetime (40) years, average load factor for base-load plants (85

81 How Stuff work http://www.howstuffworks.com/index.htm

82 http://www.fuelcells.org/basics/faqs.html

83 OECD: Projected Costs of Generating Electricity: 2005 Updates.

percent) and discount rates (5 percent and 10 percent) and base year is July 2003. Table 8.4 shows the component and levelized cost of electricity generation for fuel cell.

Table 8.4
Levelized Cost of Electricity Generation from Fuel Cells
(2003 USD/MWh)

Technologies – Country/plant type	Dis. Rate	Net Capacity Mw	Overn Const Cost – Musd	Lev. Capital Cost	Lev. O&M	Lev. Fuel Cost	Lev. Electricity Cost
USA-DG1:Gas/fuel cell/none	5%	10	21	17	22	34	73
USA-DG1:Gas/fuel cell/none	10%	10	21	30.4	22	33.7	86.2
USA-DG3:Gas/fuel cell/FF,SCR	5%	2	1.6	6.4	8.2	43.8	58.4
USA-DG3:Gas/fuel cell/FF,SCR	10%	2	1.6	11.5	8.2	43.4	63.1
USA-DG2:Gas/fuel cell/FF,SCR	5%	1	1	32.2	14.3	48.1	94.6
USA-DG2:Gas/fuel cell/FF,SCR	10%	1	1	56.7	14.3	47.7	118.7

SOURCE: IEA, Projected Cost of Generating Electricity 2005 Update, OECD, Paris, France.
NOTES: **DG,** distributed generation; **FF,** Fabric filters; **None**, no emission control equipment included in the cost; **SCR,** Selective catalytic reduction (de NO_x);.

In 2003 the US Congressional Budget Office (CBO) examined the component costs of fuel cell and estimated the levelized cost of electricity generation. Future costs and output flows were discounted at an annual rate of 7 percent to get the levelized costs of electricity generation. The result of this estimation is shown in table 8.5.

Table 8.5
Costs and Performance Characteristics of Fuel Cells
(2000 USD)

Technology	Fuel Cell - CHP
Capacity (KW)	200
Heat rate (Btu/kWh)	5,106
Capital Cost ($/kW)	3,674
O&M ($/kWh)	0.010
Fuel Cost ($/KWh)	0.029
Service life (Years)	12.5
Levelized cost of Electricity ($kWh)	0.09

SOURCE: Congressional Budget Office based on data from the Department of Energy's National Renewable Energy Laboratory and Energy Information Administration.

The cost and performance characteristics of fuel cell that input to the US electricity capacity planning sub- models is illustrated in table 8.6. it should be noted that CERI believes that the cost of operation and maintenance is extremely high and this variable should be investigated .

Table 8.6
Cost and Performance Characteristics of Fuel Cells
(2003 USD)

Technology	Fuel cell
Capacity (MW)	10
Heat rate (Btu/kWh)	7,930
Overnight Cost ($/kW)	4,250
Variable O&M (mills/kWh)	42.40
Fixed O&M ($/KW)	5.00
Lead times (Years)	3

SOURCES: United States Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38.

CHAPTER 9
NATURAL GAS AND COAL PRICES

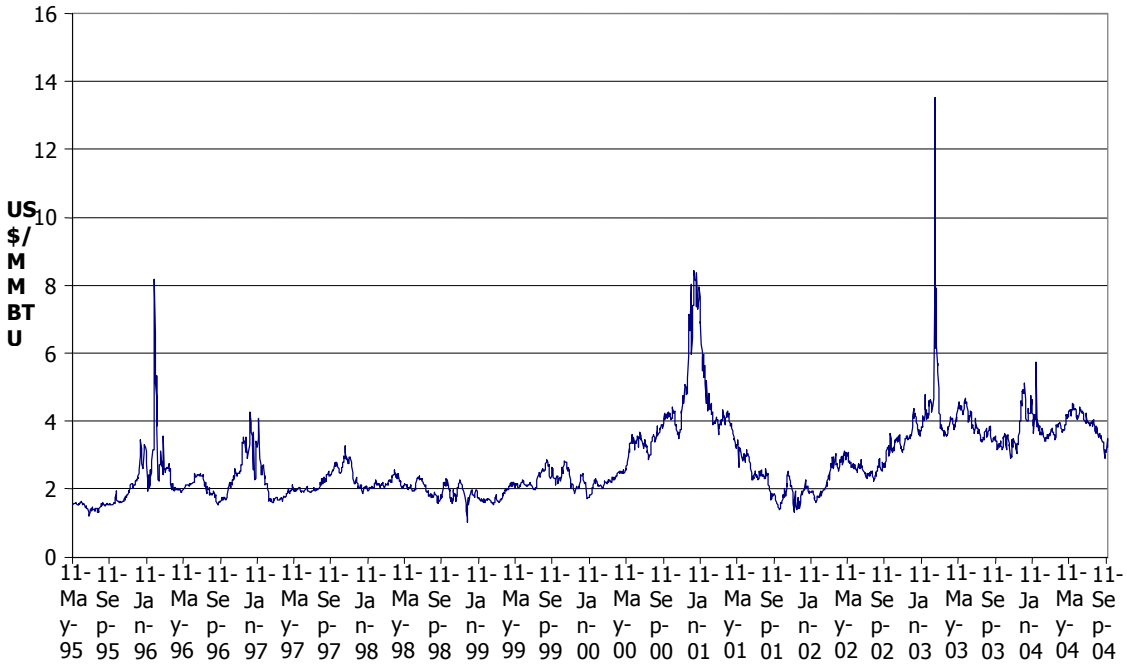
9.1 Overview

The choice of fuel impacts electricity generation efficiency, transportation costs, storage costs, emission levels and operating costs. Since generation cost of gas-fired plants are very sensitive to future gas prices, this chapter deals with natural gas price volatility and future pieces of natural gas and coal.

9.2 Gas Price Volatility

Henry Hub daily closing prices of natural gas between May 11, 1995 and September 17, 2004 are obtained from NYMEX. The data includes 2330 observations, which correspond to trading days with weekends and holidays removed. The nominal price is deflated to control for inflation, Figure 9.1 shows the real Henry Hub closing price for the whole period, in 1994 US dollars.

Figure 9.1
Real Natural Gas Price at Henry Hub



The graph clearly illustrates three major price spikes that occurred in winters of 1995-1996, 2000-2001 and 2002-2003. Overall, we are given a rough idea that the natural gas price is volatile and is subject to a lot of factors that affect it.

The winter of 1995-1996 was exceptionally cold. The town of *Hell*, Michigan, was in the news during this extremely cold winter when it froze over. The cold temperatures drove the natural gas price up.

Natural gas prices rose dramatically in 2000 and remained high through much of the first half of 2001. Contributing to the price increases in 2000 were an increase in natural gas consumption and a decline in the productive capacity of the U.S. natural gas industry, which limited production responses. Rising prices at the beginning of the natural gas storage refill season in April 2000 resulted in lower levels of injections than normal and unusually low levels of natural gas in storage at the start of the 2000-2001 winter. Exceptionally cold weather in November and December 2000 caused spot prices to spike higher, exceeding $10 per million Btu on a few days in late December and early January 2001. Cold weather was a key reason for the increases in natural gas demand during 2000, particularly in the residential and commercial sectors, which use natural gas primarily for space heating. Although temperatures moderated by mid-January 2001 and were near or slightly above normal in February and March 2001, the 2000-2001 heating season overall was the first colder-than-normal winter since 1995-1996[84].

Based upon fundamental supply-demand analysis, the factors that caused high gas prices for the winter 2002-2003 are colder weather, lower volume of working gas storage, lower production levels, higher oil prices and higher demand from the US.[85]

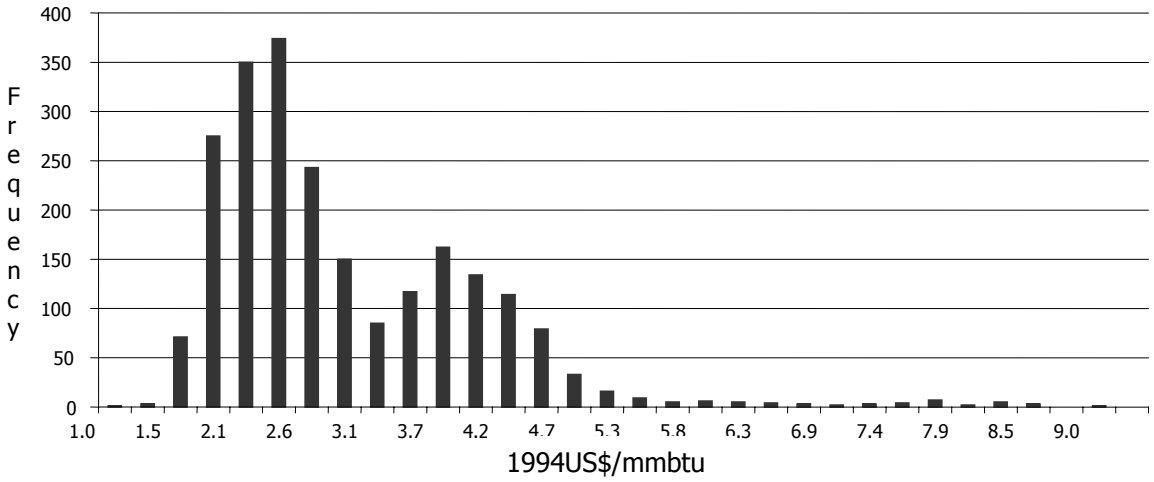
The histogram of figure 9.2 shows the distribution of the price series. The histogram is a graphical display showing the distribution of data values in a sample by dividing the range of the data into non-overlapping intervals and counting the number of values which fall into each interval. These counts are called frequencies. Bars are plotted with height proportional to the frequencies[86].

84 Energy Information Agency (EIA): "U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply", available at http://www.eia.doe.gov/oiaf/servicerpt/natgas/chapter1.html.

85 "Natural Gas Prices are Rising", Maryland Public Service Commission, Office of External Relations, available at www.psc.state.md.us/psc/Info/brochures/gasRising.htm.

86 www.statlets.com/usermanual/glossary.htm

Figure 9.2
Histogram of Daily Distribution of Natural Prices



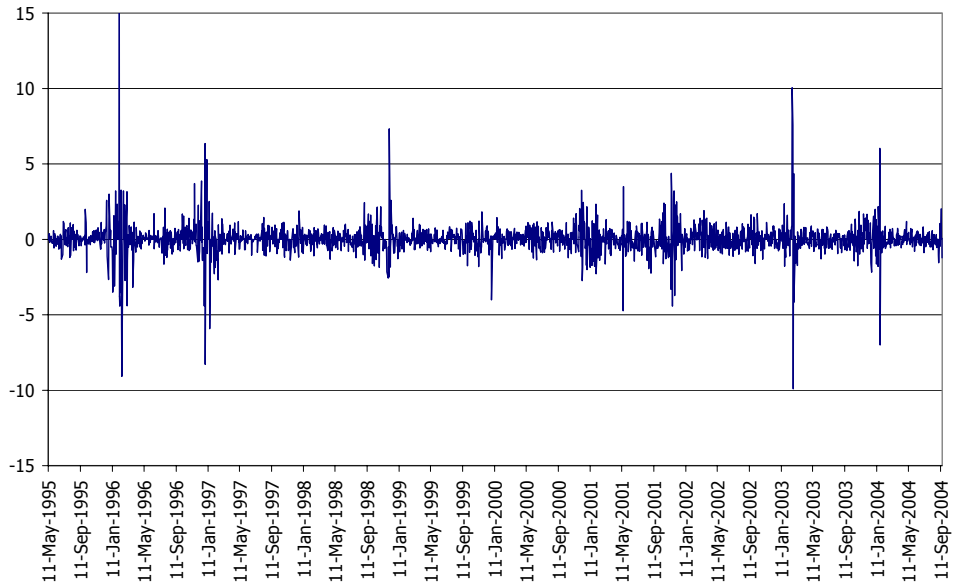
It is apparent that the series is not normally distributed; in fact there is a large right-hand side tail. Gas prices exhibit what is called lognormal behavior due to the simple fact that prices have no real upside constraint, but the downside is constrained by zero, as market prices can never go negative. Therefore, over a large sample space of prices, a resulting random distribution (bell-shaped curve) will be skewed to the positive around a sample mean (or "average") price, which is US$2.78/MMBtu in this case. This is the essence of gas price log normalcy.

To see how gas prices changed over time we calculate normalized price volatility. Volatility, in analytical terms, is also known as a numerical variance, or more precisely, standard deviation from a "mean" or average price trend. It says nothing about the direction of price movement. The calculation takes the natural log of the price differences (P_t-P_{t-1}) and normalizes the series by dividing all data points by the standard deviation.

Volatility_t = ln (P_t-P_{t-1}) / standard deviation of all (ln(P_i-P_{i-1}))

Figure 9.3 shows the volatility of natural gas prices. From the graph we can observe that volatility fluctuations tend to cluster together, especially before and after a big shock (for example, winter 1995-1996).

Figure 9.3
Volatility of Real Natural Gas Price at Henry Hub



9.3 Natural Gas Price Forecasts

Future natural gas prices in North America will be affected by many factors, including demand growth and the types of supply sources (conventional and non-conventional) and their costs to bring them to market. Two graphs follow, one with Sproule's[87] gas price outlook to 2025 and one with the EIA's AEO2005[88] outlook.

Figure 9.4 show the Sproule forecasts annual Henry Hub natural gas prices. An upward trend from 1997 is expected to last for a decade to 2007, and then prices are expected to fall in 2008 as the new set of LNG terminals in North America come on-line. After 2010, demands and supplies in North America are expected to stay in balance and prices are expected to increase at a moderate annual rate of 1.5%.

87 www.sproule.com

88 Energy Information Administration (EIA)'s Annual Energy Outlook (AEO) 2005, released February 2005 - Report #: DOE/EIA-0383(2005), www.eia.doe.gov

Figure 9.4
Natural Gas Price Forecast from Sproule
Nominal USD/mmbtu

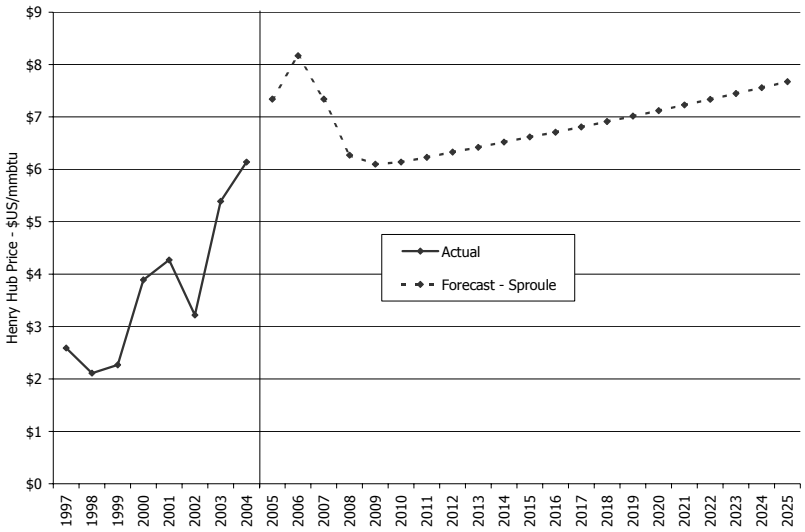


Figure 9.5 shows the EIA's AEO2005 gas price outlook. Note that the EIA's forecasts are for the Lower 48 (US suppliers) average wellhead price, which does not include transportation costs to deliver gas to consumers, hence the lower levels than the Henry Hub prices from the Sproule forecast above.

The AEO2005 includes forecasts for many economic indicators and energy sectors[89]. In AEO2005 the projected growth in real GDP, based on 2000 chain-weighted dollars, is 3.1 percent per year from 2003 to 2025. Its oil price forecasts go from $25 per barrel in 2010 to $30 per barrel in 2020. Recent variability in crude oil prices demonstrates the uncertainty inherent in forecasting crude oil markets, which generally widens as the time horizon extends into the future.

The AEO2005 forecast of end-use sector energy consumption shows higher growth for petroleum and natural gas than occurred from 1980 to 2003 but lower projected growth in electricity consumption. Much of the projected growth in petroleum consumption is driven by increased demand in the industrial sector for petrochemical and manufacturing applications as economic activity expands, and in the transportation sector as improvements in efficiency fail to offset increases in miles traveled.

Natural gas consumption is expected to increase in the residential, commercial, and industrial sectors as environmental and economic pressures benefit natural gas at the expense of

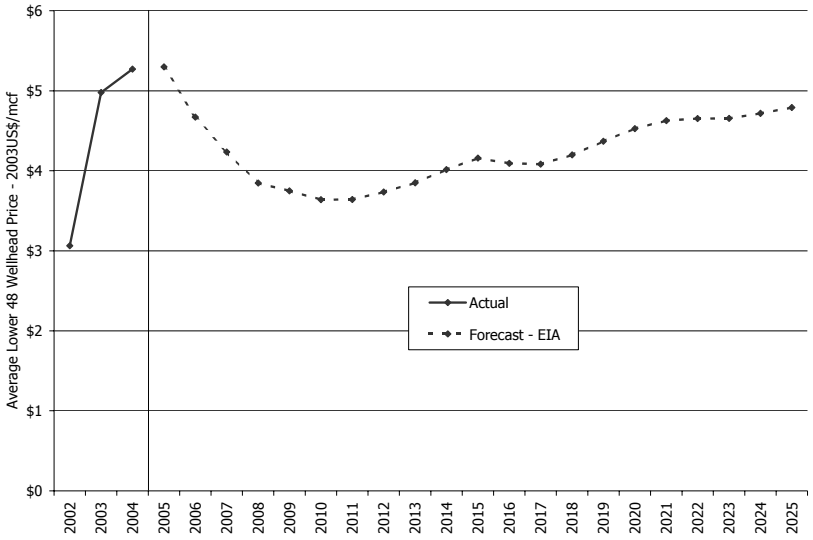
89 Please see the Forecast Comparisons section in the EIA's AEO2005 at www.eia.doe.gov/oiaf/aeo/forecast.html.

petroleum and coal consumption. Coal consumption in those end-use sectors is expected to decline slightly as a result of increased fuel switching and growing concern about emissions. Electricity is expected to remain the fastest growing source of delivered energy. Its growth does not outpace historical rates, however, because many traditional uses of electricity (such as for air conditioning) approach saturation while average equipment efficiencies rise.

There are considerable differences among published forecasts of natural gas prices, production, consumption, and imports. The differences highlight the uncertainty of future market trends. Natural gas for domestic consumption is supplied by domestic production and net imports. AEO2005 forecasts show domestic production providing a decreasing share of total natural gas supply. The volume of net imports varies significantly among the forecasts, as does the mix of net imports. GII, SEER, and Altos expect a decline in net pipeline imports of more than 50 percent between 2003 and 2025, the AEO2005 reference case projects, for net pipeline imports, a decline of about 20 percent over the next two decades.

Figure 9.5 shows that the natural gas prices are expected to rise until about 2008, and then drop with the new LNG supplies coming on-stream. The wellhead prices are expected to gradually increase to 2025 as more difficult (and costly) supplies are tapped and as capital and operating costs increase (predicted inflation rates remain positive to 2025).

Figure 9.5
Natural Gas Price forecast from the EIA

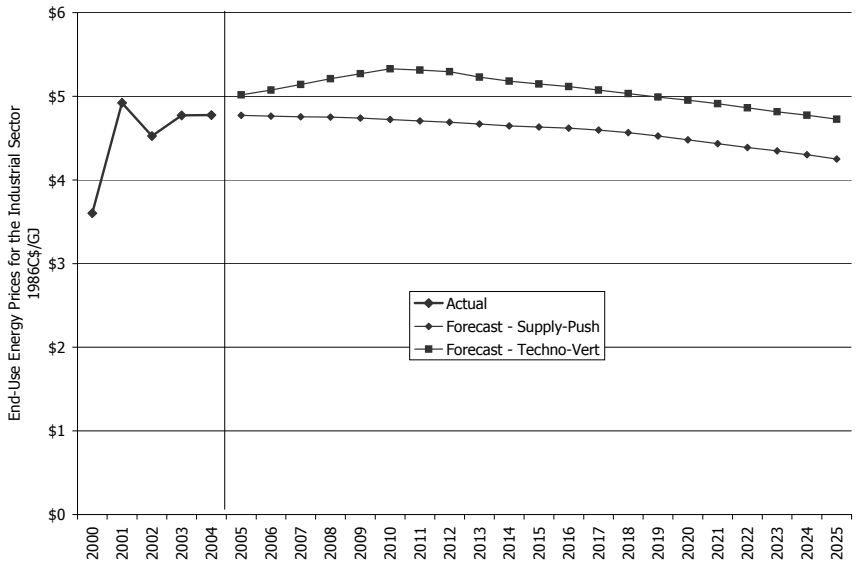


The National Energy Board (NEB)[90] provides future expected natural gas prices delivered to industrial consumers in Ontario. Figure 9.6 shows the forecast for two scenarios: a supply-push case and a techno-vert case.

The supply-push case assumes more development of conventional North American sources, where as the techno-vert scenario assumes development of more unconventional gas sources, such as the Arctic and LNG expansions.

Both of these case forecasts, in real dollar terms, predict that prices of delivered natural gas to industrial consumers in Ontario will decrease after about 2010. This again may reflect the assumption of LNG supply or other sources coming on stream by about 2010, which should depress prices.

Figure 9.6
Natural Gas Price Forecasts from the NEB



9.4 Coal Prices

Coal prices have changed over the last half century, though the largest movement in coal prices came in the mid 1970's to early 1980's. This was also when oil prices boomed upwards. Figure 9.7 includes bituminous coal prices in the US and the annual average US refiner's acquisition costs of imported crude oil.

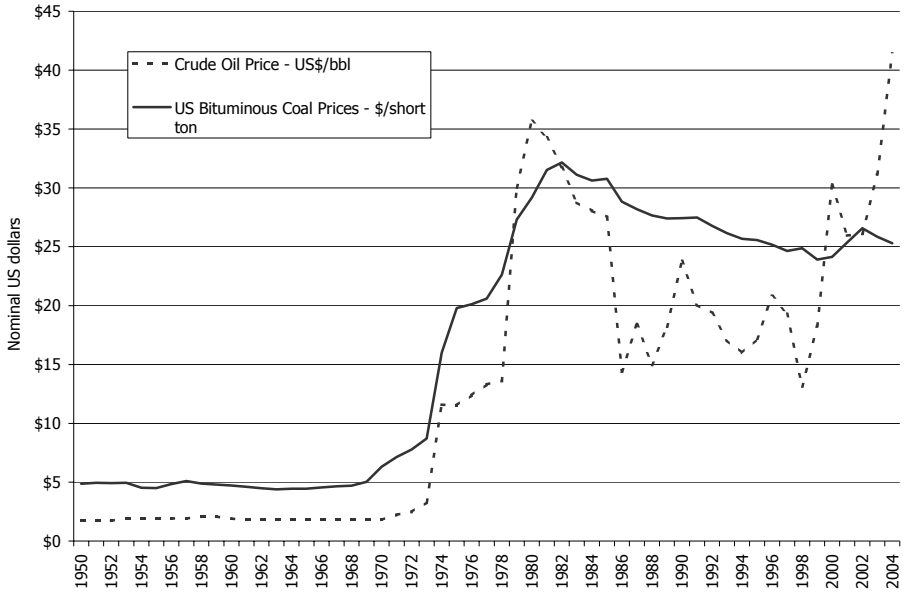
From 1950 to the early 1970's, coal and oil prices remained relatively stable (on an annual basis). The next ten years brought huge escalations to coal and oil prices. Since then, coal has remained

90 Canada's Energy Future: Scenarios for Supply and Demand to 2025, Appendix 3: Demand - www.neb-one.gc.ca/energy/SupplyDemand/2003/SLK/A3_4_e.slk.

in the $23 - $33 per short ton range, while oil prices have jumped from $15 to more than $40 per barrel. Nevertheless, as oil prices remain at high levels, it seems that coal will also remain at its high level.

Along with oil prices, the demand for US coal will play a part in prices, as well as the progression of clean coal technology and what it could mean for coal –fired generation.

Figure 9.7
Coal versus Crude Oil Prices



9.5 Coal Price Forecasts

Forecasts for coal prices from the EIA's AEO2005 outlook are shown in Figure 9.8. The coal prices represents the US export price of coal, in 2003US$ per short ton. It indicates that the coal prices are not expected to dip below $35 per short ton for the next two decades.

Sproule and the EIA also expected oil prices to sustain at higher levels – Sproule's annual WTI forecasts for oil prices do not fall below $42 per barrel and the EIA's average US imported crude oil price forecasts do not dip below $24 per barrel for the next two decades.

Figure 9.8
Coal Price forecasts from the EIA

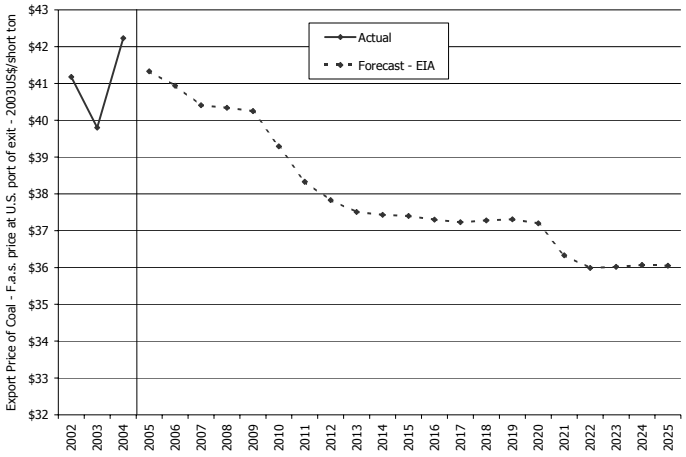
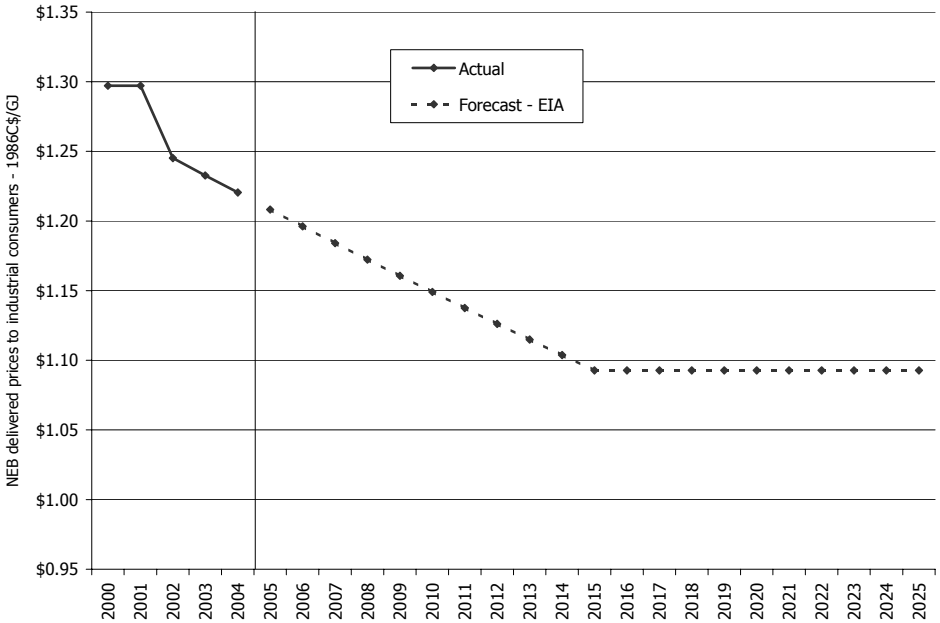


Figure 9.9 shows the NEB price forecast. The NEB predicts delivered coal prices to Ontario industrial consumers are also expected to decrease, in real dollar terms, over the next two decades.

Figure 9.9
Coal Price forecasts from the NEB



9.6 Summary of Forecasts

The Price forecast for oil, natural gas and coal from a variety of sources[91] are presented in tables 9.1, 9.2 and 9.3 respectively. The data of figures 9.4 to 9.9 are also presented in Table 9.4.

Table 9.1
Oil Price Forecasts

		2005	2010	2015	2020	2025
Sproule[1]	$US/barrel	56.93	43.09	46.42	50.01	53.87
AEO2005[2]	2003US$/bbl	33.56	24.50	26.27	28.06	30.00
GII	2003US$/bbl		27.08	25.58	26.66	27.12
IEA	2003US$/bbl		23.25	25.37	27.48	29.07
Altos	2003US$/bbl		21.92	22.67	23.93	24.60
PEL	2003US$/bbl		25.00	27.00	27.00	29.00
PIRA	2003US$/bbl		34.75	39.15		
DB	2003US$/bbl		24.00	24.00	24.00	24.00
EEA	2003US$/bbl		26.58	25.55	24.93	
SEER	2003US$/bbl		26.13	28.40	28.25	29.00
EVA	2003US$/bbl		28.99	28.39	30.97	34.77

[1]WTI at Cushing, Oklahoma
[2]Average US Refiner's Acquisition cost of Imported Crude Oil

Table 9.2
Natural Gas Price Forecasts

		2005	2010	2015	2020	2025
Sproule[1]	$US/mmbtu	7.34	6.14	6.62	7.12	7.67
AEO2005[2]	2003US$/mcf	5.30	3.64	4.16	4.53	4.79
GII	2003US$/mcf			3.84		3.96
EEA	2003US$/mcf			4.69		
EVA	2003US$/mcf			3.71		3.98
PIRA	2003US$/mcf			5.14		
DB	2003US$/mcf			3.66		3.66
SEER	2003US$/mcf			3.9		4.26
Altos	2003US$/mcf			3.92		5.78

[1]Henry Hub
[2]Average lower 48 wellhead price

Table 9.3
Coal Price Forecasts

	2005	2010	2015	2020	2025
AEO2005[1]	25.87	24.89	24.42	24.66	25.95
EVA			27.00	27.22	27.54
Hill			26.01	27.03	
GII			23.63	22.69	21.79

[1]Delivered priced to US power producers- 2003US$/short ton

91 Please see the AEO2005 outlook for more details: http://www.eia.doe.gov/oiaf/aeo/forecast.html.

Table 9.4
Prices Presented in Figures 8.4 – 8.9

	Figure 8.4	Figure 8.5	Figure 8.6: S-P	Figure 8.6: T-V	Figure 8.8	Figure 8.9
1997	2.59					
1998	2.11					
1999	2.27					
2000	3.89		3.60	3.60		1.30
2001	4.27		4.92	4.92		1.30
2002	3.22	3.06	4.53	4.53	41.18	1.25
2003	5.39	4.98	4.77	4.77	39.80	1.23
2004	6.14	5.27	4.78	4.78	42.23	1.22
2005	7.34	5.30	4.77	5.02	41.33	1.21
2006	8.17	4.67	4.76	5.08	40.94	1.20
2007	7.34	4.23	4.76	5.14	40.41	1.18
2008	6.27	3.85	4.75	5.21	40.34	1.17
2009	6.10	3.75	4.74	5.27	40.25	1.16
2010	6.14	3.64	4.72	5.33	39.29	1.15
2011	6.23	3.64	4.70	5.31	38.33	1.14
2012	6.33	3.74	4.69	5.29	37.83	1.13
2013	6.42	3.85	4.67	5.23	37.51	1.11
2014	6.52	4.02	4.65	5.18	37.43	1.10
2015	6.62	4.16	4.63	5.15	37.4	1.09
2016	6.71	4.09	4.62	5.12	37.3	1.09
2017	6.81	4.08	4.60	5.07	37.23	1.09
2018	6.91	4.20	4.57	5.03	37.28	1.09
2019	7.02	4.37	4.53	4.99	37.31	1.09
2020	7.12	4.53	4.48	4.95	37.2	1.09
2021	7.23	4.63	4.43	4.91	36.33	1.09
2022	7.34	4.65	4.39	4.86	35.99	1.09
2023	7.45	4.66	4.35	4.82	36.02	1.09
2024	7.56	4.72	4.30	4.77	36.07	1.09
2025	7.67	4.79	4.25	4.73	36.05	1.09

Figure 8.7

	Coal	Oil
1950	4.86	1.71
1951	4.94	1.71
1952	4.92	1.71
1953	4.94	1.93
1954	4.54	1.93
1955	4.51	1.93
1956	4.83	1.93
1957	5.09	1.90
1958	4.87	2.08
1959	4.79	2.08
1960	4.71	1.90
1961	4.6	1.80
1962	4.5	1.80
1963	4.4	1.80
1964	4.46	1.80
1965	4.45	1.80
1966	4.56	1.80
1967	4.64	1.80
1968	4.7	1.80
1969	5.02	1.80
1970	6.3	1.80
1971	7.13	2.24
1972	7.78	2.48
1973	8.71	3.29
1974	16.01	11.58
1975	19.79	11.53
1976	20.11	12.38
1977	20.59	13.30
1978	22.64	13.60
1979	27.31	30.03
1980	29.17	35.69
1981	31.51	34.28
1982	32.15	31.76
1983	31.11	28.77
1984	30.63	28.06
1985	30.78	27.53
1986	28.84	14.38
1987	28.19	18.42
1988	27.66	14.96
1989	27.4	18.20
1990	27.43	23.81
1991	27.49	20.05
1992	26.78	19.37
1993	26.15	17.07
1994	25.68	15.98
1995	25.56	17.18
1996	25.17	20.81
1997	24.64	19.30
1998	24.87	13.11
1999	23.92	18.25
2000	24.15	30.30
2001	25.36	25.94
2002	26.57	26.09
2003	25.86	31.14
2004	25.30	41.42

CHAPTER 10
COMPARATIVE SUMMARY

In this chapter, we summarize the technologies that are described in the report. A summary of the operating characteristics of existing utility generating units is illustrated at the end of the chapter. A more detailed technical and economic summary is given as an insert inside the back cover of this report.

Nuclear energy, like coal, is employed to raise steam for use in steam turbines to generate electricity. Capital costs and construction periods are somewhat higher than for coal-fired or gas-fired plant, but fuel costs are considerably lower. Economies of scale are substantial, so nuclear generating units are larger on average than those employing fossil fuels. Relative to oil, natural gas or coal, nuclear fuel is very compact (i.e. it has a high ratio of energy content to mass) and thus is inexpensive to transport. There are no emissions of greenhouse gases or ozone precursors during the normal operating life of a nuclear plant, although there are environmental impacts associated with the construction phase. Because of its relatively high capital costs and low fuel costs, nuclear has traditionally been employed in base-load generation.

Although nuclear is somewhat dispatchable, its dispatchability is rarely important because the circumstances in which nuclear units are "available but not operating" are rare.

The capital costs of hydro are highly site-specific, and essentially all of the costs associated with hydro are capital costs. Rational generation expansion requires the development of the cheapest hydro sites first. Generally speaking, therefore, the remaining undeveloped hydro sites are more expensive to develop than those already in operation. Thus generic hydro costing is of little value in specific situations. Mark Bartlett et al.[92] note that among the provinces, "Québec and Ontario have the largest undeveloped small hydro resources, followed by British Columbia and Newfoundland." There is, however, no undeveloped hydro site in Ontario equivalent to Niagara Falls, although there is untapped potential at the Niagara River Beck 3 site. Earlier this year the Ontario government[93] made 18 sites available for waterpower development.

Because of its dispatchability, zero fuel costs and low forced outage rate, hydro is highly valued in economic dispatch where it is employed in both base load and peaking. Dispatchability of hydro can be further improved by enlarging reservoirs and employing pumped storage.

Wind technology employs turbines that transform the kinetic energy of wind to generate electricity. The current generation of wind turbines typically uses three blades, whose speed and power are controlled by either pitch or stall regulation. Wind turbines are designed to produce high-quality, network-frequency electricity whenever enough wind is available. Because the

[92] Bartlett, M. et al., Environmental Ststainability through Art and Science, available on the Internet at www.c2p2online.com/docduments/w005CPPR-Mark_Bartlett.pdf

[93] Ontario Ministry of Energy News Release of March 7, 2005, available on the Internet at www.energy.gov.on.ca/index.cfm?fuseaction=renewable.hydro.

technology depends on the availability of wind, it is not dispatchable. Even so, there is a strong likelihood that some wind energy will be available at system peak, so wind energy is more somewhat more valuable to the system than the fossil fuel that it displaces.

Coal, like hydro, has long been employed in generating electricity. Its performance characteristics in terms of reliability and utilization are similar to those of generation by other fossil fuels or nuclear. Relative to other fossil fuels it has a lower fuel cost per unit of energy and a greater abundance of mineral reserves, but a higher CO_2 emission rate; it also fosters acid precipitation due to its sulphur content, and releases particles into the atmosphere. These particles are objectionable both for their health impact and for the "opacity" or reduced visibility that they cause. Coal-fired generation is used for intermediate load in Ontario and is base-loaded in other provinces.

Cleaner coal technology seeks to reduce emissions by reducing the formation of pollutants. A parallel approach is to develop more thermally efficient systems so that less coal is used to generate the same amount of electricity. Clean coal technologies in conjunction with various coal types are pulverized coal combustion with either sub-critical or supercritical steam cycle, and atmospheric or pressurized fluidized bed combustion.

Gasification of coal or biomass offers the potential to employ a sufficiently clean fuel in a gas turbine, which in turn can be operated in combined cycle with a steam turbine. Gasification can prevent many pollutants from entering the atmosphere; combined cycle operation offers the prospect of higher thermal efficiency, enabling a given quantity of electricity to be produced from a smaller quantity of fuel.

Gas turbines in single cycle have commonly been employed as peaking units. In combined cycle with steam turbines with using natural gas as a fuel, a very high thermal efficiency is achieved, particularly if there is an industrial use for the heat that is ejected by the steam turbine. Combined-cycle technology, however, is too capital-intensive to be used merely for peaking, although it could be employed to serve intermediate loads. The levelized cost of all technologies using natural gas as fuel is predominantly the fuel cost, and thus is highly sensitive to the price of natural gas.

Photovoltaic technology converts sunlight directly into direct current, whereas solar thermal technology converts sunlight into thermal energy and then into electricity. The costs of energy from solar and other renewable sources have come down substantially in recent years, but so far solar has been limited to niche markets. Solar, like other renewable, is considered in terms of potential contribution to system supply, rather than as an on-site source of electricity and heat. Solar energy is available when the sun shines, and therefore is not dispatchable. As Ontario's Electricity Conservation & Supply Task Force (ECSTF, January 2004) explained, "Intermittent Generation is provided by generators that produce energy only when conditions are suitable for operation. . . Intermittent generators can be valuable as a source of energy for load

displacement, but their inherent unpredictability does not allow them to be used for base load or peaking purposes."[94]

Fuel cells combine hydrogen and oxygen to produce water, in a process that does not entail combustion. The energy from this process takes the form of electricity and heat. In existing commercial operations, the hydrogen is derived on site by the steam-reforming of natural gas. The thermal efficiency of steam-reforming plus fuel cell operation is substantially higher than obtainable by ordinary gas combustion technology. The higher the price of natural gas the more competitive the fuel cell alternative becomes.

A summary of the operating characteristics of existing utility generating units is illustrated below and the component cost of electricity generation is given as an insert inside the back cover of this report.

Table 10.1
Selected Operating Statistics for Canadian Generating Units

Fuel/Technology	Period	OP Factor (%)	ABNOF (%)	FOR (%)	DAUFOP (%)
Hydraulic	2003	69.82	21.62	1.87	1.59
	1999-2003	72.46	18.97	1.93	1.70
Steam turbine-coal	2003	80.37	5.19	5.94	9.14
	1999-2003	79.12	4.84	6.73	9.38
Steam turbine-oil	2003	60.61	20.11	4.63	4.39
	1999-2003	44.42	28.77	8.61	6.95
Steam turbine-gas	2003	12.96	71.52	18.16	10.45
	1999-2003	46.06	33.91	15.31	13.39
Combustion turbine	2003	13.19	73.97	22.96	8.72
	1999-2003	18.68	69.80	21.06	9.20
Nuclear	2003	76.27	2.07	10.07	11.91
	1999-2003	81.90	0.67	5.66	7.50

Source: Canadian Electricity Association, 2003 Generation Equipment Status Annual Report.

The values of "OP FACTOR" and "ABNOF" reflect the degree of utilization of the units, whereas the values of "FOR" and "DAUFOP" are measures of reliability. The Canadian electricity Association define (OP factor), (ABNOF), (FOR), and (DAUFOP) as follows.

- **Operating Factor or OP FACTOR (%)**: Total Operating Time (whether under normal operation, under forced derating or under scheduled derating) divided by Unit Hours, the total number of hours in a year [8760 except in a leap year].
- **Available but not Operating Factor or ABNOF (%)**: 100 percent times (number of hours available for normal operation but not operating plus number of hours available but not operating under forced derating [typically due to a component failure] plus

[94] Electricity Conservation & Supply Task Force, "Tough Choices: Addressing Ontario's Power Needs", (final report to the Minister), p. 48.

number of hours available but not operating during scheduled deratings), all divided by Unit Hours as defined above.

- **Forced Outage Rate or FOR (%)**: 100 percent times the ratio of Total Forced Outage Time to (Forced Outage Time + Total Operating Time as defined above). Total Forced Outage Time is the sum of hours in a forced outage state, hours in a forced extension of a maintenance outage and hours in a forced extension of a planned outage.

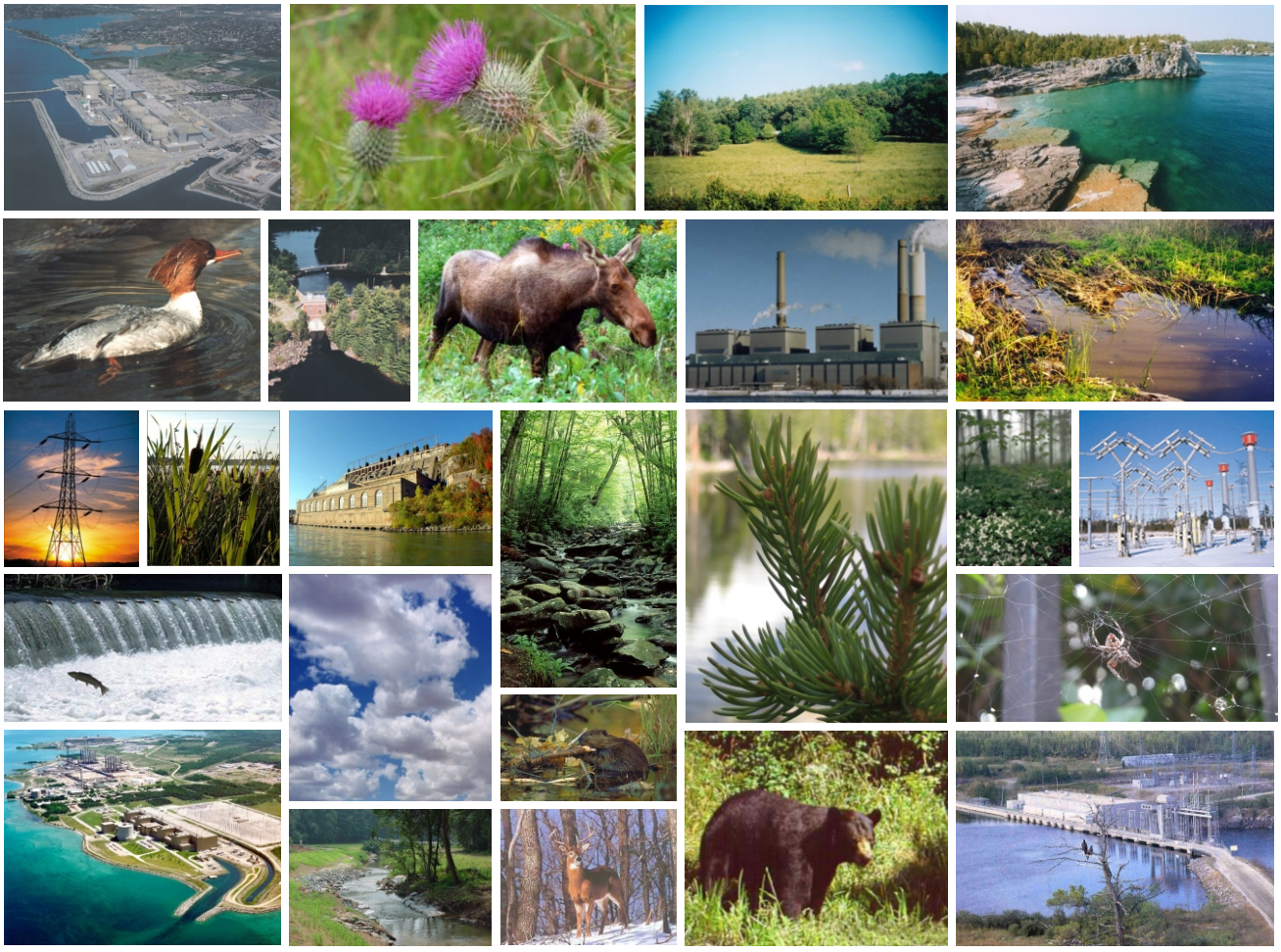
- **Derating Adjusted Forced Outage Probability or DAUFOP (%**): The probability that a generating unit will not be available when required (derating included).

Table 10.2, which is given as an insert in the back of this report illustrates the performance and cost characteristics of electricity generation technologies.

Ontario Power Authority

Final Report:

METHODS TO ASSESS THE IMPACTS ON THE NATURAL ENVIRONMENT OF GENERATION OPTIONS



Prepared For:

The Ontario Power Authority

Prepared By:

SENES Consultants Limited

September 2005

METHODS TO ASSESS THE IMPACTS ON THE NATURAL ENVIRONMENT OF GENERATION OPTIONS

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1.0 INTRODUCTION

Beginning in 2007 and continuing to 2009, the "largest and most significant electricity system change ever undertaken in Ontario…" will see the replacement of roughly 6500 megawatts (MW) of coal fired generation phased out. This generation is set to be replaced with cleaner electrical generating options (IESO, 2005). Already, 650MW of gas-fired generation has been installed and it is expected that 515MW of nuclear and 370MW of renewable generation will be coming online in the near future. In addition, a further 9000MW of projects including conservation initiatives, power purchase agreements and additional renewable generation are planned (IESO, 2005).

The current electricity mix in Ontario is 36.1% nuclear, 25.6% hydro, 21.4% coal, 16.5% oil and/or gas and 0.2% miscellaneous, for a total installed capacity of 30,114MW. The future generation mix must account for not only market efficiency, but also resource adequacy to allow for fuel supply flexibility and to ensure that the province is not vulnerable to either supply or cost issues for any one fuel type. These issues must also be balanced with the need for baseload and peaking generation (IESO, 2005) and a desire to decrease the provincial impact on the natural environment from electrical generation. The Ontario Power Authority (OPA) is charged with developing the long-term electrical supply forecast and balancing all these issues.

Reporting to the Ontario Legislature through the Ministry of Energy, the OPA is a non-profit statutory corporation that is headed by an independent board of directors. The OPA is licensed and regulated by the Ontario Energy Board and all operating costs are recovered in electricity user fees.

Under the *Electricity Act* s.25.2, the OPA's objectives include not only forecasting and planning electricity resources for Ontario, but also pricing, developing integrated power system plans, contracting new generation or demand side management programs, and facilitating the diversification of electrical resources. A part of this overall planning is determining how electrical generation options will impact the natural environment of Ontario.

The Minister of Energy has recently requested that the OPA begin to develop an Integrated Power System Plan (IPSP) and provide to the government a plan for the future long-term supply to meet Ontario's electricity needs. In developing this supply mix, the OPA was asked to consider the following three factors:

1. Taking into account the conservation target set for 2007, make recommendations regarding appropriate conservation targets in Ontario for 2015, 2020 and 2025.
2. Taking into account the renewable energy targets already set for 2007 and 2010, make recommendations regarding potential new renewable energy options in Ontario for 2015, 2020 and 2025.

3. Provide the government with recommendations regarding how energy demand forecasts for Ontario can be met.

This process tasked to the OPA is expected to be completed with expert advice from external and Ontario sources as well as with stakeholder input. The process incorporates a number of studies including, for example, economic and social considerations. One of these studies that will be incorporated into the IPSP analysis is the environmental impact and sustainability of generation and supply mix options. In order to respond to this need, the OPA retained SENES Consultants Ltd. (SENES) to develop a methodology to assess the impacts to the natural environment of different generation options.

1.1 TERMS OF REFERENCE

SENES is tasked with providing the OPA with a methodology that will assess the impacts of generation options on the natural environment. SENES was asked to develop a method that would identify and quantify relevant environmental factors and be able to assess long-term planning, capture cumulative impacts and provide an indication of sustainability for generation options and supply mix plans.

In addition, SENES was asked by the OPA to specifically identify how carbon credits were valued around the world and in Canada in order to provide a baseline for expected values. The OPA also requested that SENES identify the impacts to the natural environment from a new interconnection with Manitoba Hydro (the OMI Project).

In order to carry out these tasks, SENES developed a multi-step process to evaluate the natural resource impacts and sustainability of generation options for the province of Ontario. These steps are listed below. Note that the valuation of carbon credits and the OMI Project are not included as part of the methodology because they were tasked to SENES outside of the original proposal.

- Review of Other Utility Processes – brief overview of integrated resource planning exercises in other provinces and internationally. A review was also conducted of similar impact analysis studies conducted in other jurisdictions.
- Development of General Assumptions – define the assumptions that will be used in the development of the methodology, as well as the list of generation options.
- Evaluation Criteria Development – develop the possible natural resource criteria that could be used to evaluate different generation options in order to develop a workable set of ranking criteria.
- Determine Final Ranking Methodology for Generation Options – complete evaluation of generation options including ranking using the final natural resource impact criteria.

1.2 GENERATION OPTIONS CONSIDERED

The initial set of generation options was derived from the Ontario Ministry of the Environment's Guide to Environmental Assessment Requirements for Electricity Projects (2001). It was further refined through conversations with the OPA. The following is the initial list of generation options that were considered:

Nuclear Generation Technologies
- CANDU 6 – New
- CANDU 6 – Refurbished
- Advanced CANDU Reactor – ACR
- Pressurized Water Reactor – PWR
- Boiling Water Reactor – BWR

Hydroelectric Generation Technologies
- Small Hydro
- Large Hydro

Renewable Generation Technologies
- Wind power - 2 and/or 3 Blade Rotors

Thermal Power Generation Technologies
- Steam Turbine Systems
- Internal Combustion Engine
- Combined Cycle Systems
- Integrated Gasification Combined Cycle
- Fuels: Natural Gas, Synthetic Gas, Coal and Biomass

1.3 REPORT ASSUMPTIONS

A number of general assumptions were made during the process to develop this methodology including:

1. An attempt was made to consider a life-cycle approach for the planning components of all forms of generation (e.g. mining of raw fuel material through decommissioning and waste disposal).
2. That any new generation or refurbishment would utilize prevailing best management practices to minimize and/or mitigate potential natural environment impacts during all life-cycle stages including operating procedures.

3. The model would need to be easy and quick to use with minimal data requirements so that it can be applied by people who are not necessarily specialists with respect to the natural resource impacts or sustainability of electrical generation.
4. All evaluations are completed with reasonable and common practice mitigation, but not site specific or special measures that may be used for a specific generating station.
5. Broad-level environmental impacts (i.e. generalized impacts) were considered rather than site-dependant impacts that would be considered in a siting study. These broad-level impacts could be assessed across the range of generation options so that there would be a common basis for comparison.
6. Transmission and distribution requirements associated with generation options were not considered.
7. Social considerations were not part of the natural environment evaluation.
8. Transmission, as a form of providing power from other jurisdictions, was not considered to be a "generation option" at the start of the study. However, during the study, OPA asked that the impacts on the natural environment of the OMI Project specifically be considered.
9. Capacity factors, with respect to rated versus actual generation, of the various generation options were not considered except where applicable to air impacts. It is assumed that this analysis will be incorporated into either economic or engineering studies of the generation options.
10. Emergency or back-up power capabilities, such as standby diesel generators, were not considered as part of the different generation types.
11. Only generation technologies that are both commercially available and widely considered commercially viable at this time were assessed.

2.0 BACKGROUND

2.1 REVIEW OF INTEGRATED RESOURCE PLANNING DOCUMENTS

In developing its approach to the evaluation of environmental effects arising from alternative generating technologies, SENES reviewed a number of international and two Canadian Integrated Resource Planning (IRP) documents. These documents were chosen because they were held to be state-of-the-art examples of the IRP process and potentially reflective of current objectives for this study. Each document was reviewed to determine what considerations, if any, were given regarding impacts to the natural environment. The following is a summary of how the documents considered impacts on the natural environment in determining their generation mix.

2.1.1 Idaho Power - 2004 Integrated Resource Plan

While the document included no monetization of environmental considerations, there was brief recognition of "social costs" of which environmental costs were considered part. Further, in evaluating potential supply options, qualitative environmental advantages and disadvantages were identified.

Energy efficiency and demand response programs were quantified with respect to expected savings. These programs are seen by Idaho Power as a way of reducing peak demand requirements.

This document provides a concise but comprehensive review of the advantages and disadvantages of different supply options, as well as provision of carbon emission costing.

2.1.2 Hawaiian Electric Company Inc. - Draft Integrated Resource Plan 2006-2025

Within the plan, the utility and the commissions were concerned primarily with efficiency, reliability, costs, and meeting electricity needs. However, the public consultation conducted as part of the plan revealed that the public was primarily concerned with environmental protection, societal impacts and the utilization of sustainable energy resources. Despite this public concern, the plan contained very little environmental aspects although they are briefly mentioned qualitatively for marine and terrestrial environment, and quantitatively, as well as more extensively, for air emissions. The analysis of air emissions included an assessment of potential future changes to legislative requirements.

Significant effort was expended in the plan to discuss and analyze demand side management options, initiatives and potential cost/benefits of each program.

2.1.3 Puget Sound Energy - Least Cost Plan April 2005

This document looked at electrical needs and supply options without investigating the requirements of specific supply option implementation. Environmental considerations focused on air emissions - specifically CO_2. A few relevant points drawn from this consideration of carbon emissions were:

1. Current Washington law taxes new generation based on the expected future CO_2 output;
2. The economic analysis found that the inclusion of CO_2 tonnage costs made natural gas competitive with coal;
3. The largest cost risk associated with coal plants is viewed as potential carbon and greenhouse gas emission restrictions and costs; and,
4. In their economic analysis, PSE used $5/tonne beginning in 2010 and increasing by 5%/year as the cost of CO_2 emissions based on the recommendation of the National Commission on Energy Policy.

Again, demand side management was incorporated in the analysis.

This document provides useful information regarding carbon emission costing in the U.S., including through the application of taxes.

2.1.4 State of California - Draft Energy Action Plan II. Implementation Roadmap for Energy Policies

Although California indicates that their "overarching goal is for California's energy to be adequate, affordable, technologically advanced, and environmentally-sound", the plan does not provide any guidance regarding how environmental concerns will be implemented with the exception of the inclusion of renewable energy sources in supply mix options. Aspects that could be seen as environmental include a brief review of renewable energy options and a need to decrease climate change emissions. Otherwise, there are statements alluding to a need to "push through" new generation to get it operational as soon as possible which could be interpreted to mean that protective legislation would be pushed as well.

This plan contained a few action items with respect to efficiency improvement and demand side management initiatives.

2.1.5 Utah PacifiCorp – 2004 Integrated Resource Plan

The Utah PacifiCorp IRP provides the framework for future actions to provide reliable, least cost service with manageable and reasonable risk to its customers as well as an analytical approach for the integration of new resource alternatives with existing generation and transmission assets

and an approach to analyze results and to determine the Preferred Portfolio. However, only the discussion on Integrated Gasification Combined Cycle (IGCC) environmental impacts included reference to impacts on air emissions (NOx, SO_2 Hg) ground and surface water, land use, aesthetics, waste management, fuel mining, road transportation and storage. Other general statements concerning impacts are made for each energy generation option with focus on air emissions but no analysis with respect to environmental impacts was included in the plan. The IRP did include the associated costs of emissions in their comparison of portfolios.

Overall commonalities found in the U.S. IRPs were:

- Demand side management is viewed as a potential for power replacement (typically touted as replacement for more environmentally detrimental fuels like coal or thermal in general) and particularly for peak demand requirement reduction; and,
- There appeared to be no inclusion of environmental approval or mitigation costs in the evaluation of supply options.

2.1.6 The Environmental Impact of EDF's Energy Supply Mix: Electricite de France

This document focused on energy generation and its environmental cost in the current supply mix. As with other documents, the primary focus was on the greenhouse gas emissions. This document provides an environmental overview of each of the generation sources in EDF's energy mix and demonstrates the actions taken by EDF to limit the environmental impacts. In 2001, EDF's energy mix, as far as generation in France was concerned, consisted of 84.2% nuclear, 12.4% hydroelectric and 3.4% thermal generation. Therefore, in 2001, 96.6 % of the electricity generated in France did not result in emissions of greenhouse gases.

This document does not provide a framework analysis for environmental impacts. However, it does highlight the associated environmental impacts based on the energy mix.

2.1.7 An Electricity Supply Strategy for the United Kingdom: Council for Science and Technology

Much like Ontario, the UK electricity supply largely depends on an infrastructure laid down in the 1940s to the 1960s. Also like Ontario, the changing resource base and the challenge of climate change require a fundamental adaptation and renewal of both network and infrastructure.

The document recommends that government consider incentives that will increase the level of research and development investment and training by the industry. Investment by government in research and development should be targeted towards the development of new and renewable fuel sources, energy management and intelligent networks.

The strategy also highlights the need for large-scale non-carbon electricity generators in order to meet CO_2 targets in 2020. As the strategy points out, wind power alone will not achieve this goal. Suitable technologies suggested include nuclear and tidal generation.

Current regulatory structures in the UK have an impact on energy options and the market. The paper encourages the funding of renewable and low-carbon energy initiatives in the UK.

Overall, this document, although not specifically providing an analysis framework, does suggest increased use of renewable and low carbon technologies and stresses the importance of an appropriate supply mix**.**

2.1.8 Prince Edward Island's Energy Framework & Renewable Energy Strategy

The current energy mix in PEI includes 80% from imported petroleum based production, 13% imported oil-fired production, 6.5% from biomass based production and 0.5% from on-island wind power. Ideally the province would like to satisfy provincial demand for energy with wind power and hydrogen fuel technology within 10 years. This long term strategy requires the appropriate mix of conventional and renewable sources. The Renewable Portfolio Standard (RPS) defines the percentage of energy that will be assessed by a jurisdiction from renewable sources. However, there is nothing in the strategy pertaining to evaluation methodology or identification of environmental impacts from generation options.

2.1.9 BC Hydro 2005 Resource Options Report

The most relevant portion of this report was contained in section 5.0 which considered environmental and social attributes. Two key concepts relevant to the current study were found in this report:

- Developing environmental attributes that can assist in decision-making requires finding a balance between what is easy to measure and what is meaningful to the decision-makers;
- The role of stakeholder input into the process of creating decision criteria is critical; the measurement of stressors is relatively objective but choosing what to measure, what units to use and how to use these in making decisions depends on stakeholders' values.

BC Hydro proposed the following environmental attributes for analysis:

- Land Impacts - measured as land impacted by structures (footprint of the generating facility, roads, transmission lines, pipelines and inundated area);
- Water Impacts - hydro developments were measured based upon areas subject to dewater effects, area subject to backwater effects, footprint of facilities, fish presence, areas affected by stream crossings, and aquatic habitat effects;

- Air Impacts - measures included oxides of nitrogen, oxides of sulphur, fine particulates, mercury, volatile organic compounds and greenhouse gases.

2.2 POWER SCORECARD – A METHOD FOR REVIEWING ELECTRICAL GENERATION OPTIONS

As part of the literature search conducted for the study, SENES discovered a document titled the "Power Scorecard" (Swanson *et al*., 2005). This document was developed by a group of environmental and non-government organizations in California.

According to the authors, a group of six environmental organizations under the guidance of the Pace University School of Law Center for Environmental Legal Studies, the Power Scorecard was created to provide information to help consumers understand the environmental differences among electricity products. The Power Scorecard grades the types of generation options used to produce electricity according to an evaluation of their effects on the environment. More specifically, the Power Scorecard provides a ranking for the environmental quality of electricity products in two ways:

1. Overall Environmental Impact Rating

The Power Scorecard assigns a score to the impact a product has in each of the eight environmental areas considered by the authors to be most seriously affected by electricity production. The Overall Environmental Impact Rating combines the scores in these eight areas:

- Air Impacts
  1. Climate change
  2. Acid rain
  3. Ozone (smog) and fine particulates
  4. Air toxics (mercury)
- Water Impacts
  5. Consumption of water resources
  6. Pollution of water bodies
- Land Impacts
  7. On-site land impacts - (permanent plant footprint)
  8. Off-site land impacts - (solid waste disposal and fuel processing)

2. New Renewable Content Rating

The Power Scorecard also grades electricity products according to the percentage of electricity that can be obtained from new renewable resources.

To produce a rating for each product, Power Scorecard personnel asked electricity retailers to provide data about the specific electricity generation sources used to supply power for customers of each product. The questions relate to each of the eight environmental impacts or performance areas and to how much new renewable energy generation is used to serve consumers.

Together the two ratings show the relative environmental quality of the electricity sources suppliers are using to serve their customers and how much each supplier is investing in new renewable electricity generation.

If power developers cannot provide data on emissions or other evaluation criteria, the power scorecard has developed substitute estimates ("default estimates") of these measures based on published information on the different types of commonly used electricity production technologies.

While the rankings of different generation technologies reflect the bias of the authors, the approach of the Power Scorecard method is reasonable.

2.3 ENVIRONMENTAL ASSESSMENT OF SELECTED CANADIAN ELECTRIC POWER GENERATION SYSTEMS USING A SITE-DEPENDENT LIFE-CYCLE IMPACT ASSESSMENT APPROACH

The Canadian Electricity Association and Natural Resources Canada commissioned this study which was completed in February 2005. Scientific Certification Systems (SCS) of California, the company that actually conducted the study, developed "a methodology for benchmarking the environmental performance of generating facilities in conformance with international life-cycle standards." However, the methodology is presented as a "work in progress".

Contrary to the broad level approach taken in the current study, the SCS study used site dependent information. The SCS study also went into much greater detail in the life-cycle assessment.

The study undertook its assessment by using case studies of a wind farm in Saskatchewan, an advanced coal project in Alberta, a hydroelectric project in Manitoba, a nuclear power plant in Ontario and a retrofitted natural gas plant in Nova Scotia. For each case study, background information was provided along with a description of assumptions and an impact profile with a description of environmental significance.

Environmental efficiency ratios are calculated directly for each indicator without the application of weighting factors. The ratios were averaged to determine the overall environmental efficiency

rating for each generation option. The assumption was made that all indicators are equally significant.

Some of the key findings included:

- According to the study, the Saskatchewan wind farm demonstrates the extremely efficient nature of wind power as an option for reducing levels of impacts in the Saskatchewan electricity supply. The final efficiency ratings for any given wind power system will be determined based upon factors such as the degree to which habitats used for wind farms and associated transmission were already disturbed, any impacts to key species that may be observed and the amount and type of back-up power required due to the inherent intermittency of the wind.
- The hydropower system evaluated in this study had high environmental efficiency ratings, reflecting the low levels of impacts inherent in this power technology in most impact categories. The variance in efficiencies among different hydropower systems depends upon factors such as hydropower plant location, relative impacts on regional habitats and species as well as mitigation activities.
- In this study nuclear power systems had high efficiency ratios in most indicator categories. These ratios do vary somewhat between heavy water and light water reactor systems (light water systems deplete more energy resources per MW produced).
- The environmental efficiency ratings of natural gas power systems are dominated by two trends:
  1. relatively low efficiency ratios for the energy resource depletion indicators, reflecting the relatively high rate of resource depletion for natural gas and the correspondingly low efficiency ratio for the greenhouse gas loading indicator; and
  2. the extremely high efficiency ratios for the remaining emissions indicators, as well as the waste and physical disruption indicators.
- The range of environmental efficiency ratings for coal power systems was quite wide, depending upon a variety of factors, such as the level of impurities in the coal, the location of the coal mine and the power plant, the surrounding population density and environmental conditions, the degree of prior disturbance to mined lands, the use of advanced combustion and high-end control technologies and mitigation projects. However, the study found that newly constructed coal power can efficiently contribute to net reductions in impacts for the existing regional power pool.

2.4 LIFE CYCLE INVENTORIES FOR NUCLEAR AND NATURAL GAS ENERGY SYSTEMS AND EXAMPLES OF UNCERTAINTY ANALYSIS

A recent paper by Dones *et al.* (2005), describes the results of a life cycle analysis of nuclear and natural gas energy systems based on nuclear fuel cycles and natural gas energy systems in use in Europe. The assessment considered the cumulative environmental burdens arising from the two fuel cycles. A great deal of information is provided on both cycles. For the nuclear fuel cycle, the authors examined the radioactive emissions for each stage of the fuel cycle and report kBq of various radionuclides released to the air per kWh based on the Swiss fuel cycle They also considered the greenhouse gas emissions (in terms of CO_2 equivalent associated with each step of the fuel cycle and indicate a range of 5 to 12 g CO_2 –equiv./kWh for European nuclear energy cycles. Much of these GHG emissions arise from uranium enrichment and reprocessing of spent fuel. The authors report (European) cumulative GHG emissions (CO_2, CH_4, N_2O and others) in the European natural gas chain range from about 485 to 990 g CO_2 equiv./kWh Although the authors caution against the use of these data for comparisons of country specific fuel cycles, the results are nonetheless interesting in general terms as context for observations from the present study.

2.5 CARBON CREDITS AND TRADING SYSTEMS

SENES was asked to develop an estimate for the potential price of a carbon credit in Canada. In essence, various carbon trading regimes are used throughout the world to trade releases of greenhouse gases, specifically CO_2. As such, an in-depth literature search was conducted on the price of a "carbon credit". In addition, discussions were held with officials at the provincial and federal levels of government in Canada.

Currently in Canada, a National Offsets Trading Team is currently developing a trading mechanism. The overall objective is to create a National Offsets Trading Program (NOTP), which will be a domestic trade-off system that can be used throughout Canada. Through this program, the federal government will be a buyer. By buying carbon credits, the federal government can deny "pollution credits" to other emitters, thereby lowering GHG emissions in hopes of reaching targets set by the Kyoto Accord. The protocol for this program is still currently in the development stage.

As a component of this program a paper entitled "Offset System for GHG's" was released for public comment in 2003. A final discussion paper is expected to be released in the near future.

Discussions with officials in government alluded to the PEARL, or Pilot Emission Reduction and Removals Learning, a program which is currently looking into the feasibility of a domestic trading system in Canada. The program includes some publications that provide information on

global carbon exchanges including Carbon Market News and the Point Carbon Newsletter. The primary issue facing this domestic program is that it cannot be traded outside of Canada. At this point, no protocols have been established for how this system can be used for trading purposes between Canada and other countries.

Prices per tonne of CO_2 have been speculated for quite some time. As part of the NOTP, a price of $15/tonne has been studied in Canada for Large Final Emitters and will be based on emission rates. In the United States a price in the range of $1.50 to $49.00 has been estimated per tonne of CO_2. Specifically, in the Idaho Integrated Resource Plan estimated carbon dioxide values from $12 to $49 per tonne. In Europe, carbon credits are actively traded, similar to stocks being traded on an open exchange. Current prices range from between €15 euros to as much as €25 euros (about $22.50 CDN to $37.50 CDN). See Table 2.1 for a summary of current and anticipated carbon prices from Canada and around the world.

TABLE 2.1
CARBON PRICES

Jurisdiction	Speculated Price
Canada	$15/tonne
United States	Range of $1.50-$49/tonne
Idaho	Range of $12-$49/tonne
Puget Sound	$5/tonne
Utah – Pacific Corp.	$8/tonne
Europe	Range of €15 euros-€25 euros

Overall, officials in the government indicated that it is fairly early in this process to actually develop a price, since the system has not been completed and any Canadian system will not be compatible with other international systems. A notice in the Canada Gazette Part I (DOE, 2005) of the intent to regulate greenhouse gas emissions by Large Final Emitters (LFE) outlined how the federal government plans to implement its climate change policy with respect to greenhouse gas emission reductions by Large Final Emitters. The intended regulation includes flexible compliance options such as emissions trading system. The government would set the basic rules regarding the trading of credits and establish an electronic tracking system to act as the official record of carbon units transactions. The notice also stipulates the commitment to cap the cost of compliance for LFE to $15/tonne for the years 2008-2012.

3.0 DESCRIPTION OF GENERATING OPTIONS EVALUATED

The list of generating options to be considered, presented in section 1.2, was used as the starting point for evaluation. In order to proceed with the analysis, an expanded description for each style of generation, either fuel or technology based, was created. This chapter presents the expanded descriptions of the generation options that were used for the final evaluation of natural environment impacts.

3.1 THERMAL GENERATION OPTIONS

Thermal generation encompasses a broad range of fuel types and technologies. As a generating option, thermal presented the largest number of potential generation types.

3.1.1 Thermal Fuel Types

For thermal generation, four fuels were assessed as potential options:

1. Natural Gas - a mixture of hydrocarbon gases that occurs with petroleum deposits, principally methane together with varying quantities of ethane, propane, butane, and other gases. Natural gas is used as a fuel and in the manufacturing of organic compounds.

The evaluation of natural gas as a thermal generation fuel assumed that it would involve the use of natural gas for power generation following processing and transport (essentially methane).

2. Coal - a fossil fuel extracted from the ground either by underground mining or strip mining. It is a readily combustible black or brownish-black sedimentary rock composed primarily of carbon and hydrocarbons, along with assorted other elements, including sulphur.

The evaluation of coal as a thermal generation fuel assumed that the coal used as fuel would be bituminous and sub-bituminous coal. These two types of coal make up roughly 75% of proven Canadian coal resources. These coal types are dense, black, soft coal, often with well-defined bands of bright and dull material. They are the most common types of coal, with moisture content usually less than 20%. Generally they are used for generating electricity, making coke, and space heating. The heat content of bituminous coal ranges from 21 to 30 million Btu/tonne (24 to 35 MJ/kg) on a moist, mineral-matter-free basis (U.S. EIA, 2005).

3. Biomass - an energy resource derived from organic matter. Biomass for energy production may be derived from wood, agricultural waste and other living-cell material

that can be burned to produce heat energy. They also include algae, sewage and other organic substances and wastes that may be used to make energy through chemical processes (U.S. EERE, 2004).

In the evaluation of biomass as an energy source, it was assumed that wood waste would be the generation fuel. Note that only wood waste, a by-product of the forestry and pulp and paper industry, was analyzed in this study and no analysis was performed on crops grown or harvested specifically as a fuel source, such as switchgrass or peat.

Analysis of biomass as a fuel source is intended to represent generation that is conducted within the overall power system and not that done "behind the grid/meter".

4. Synthetic Gas - Syngas (from synthetic gas) is the name given to gases of varying composition that are generated in coal gasification and some types of waste-to-energy facilities. The name comes from their use in creating synthetic petroleum for use as a fuel.

3.1.2 Thermal Generating Technology

Following the identification of fuels that would be assessed, a list of appropriate technologies was developed for assessment:

1. Simple-Cycle Gas Turbine (SCGT)

A SCGT is a stand-alone generating plant that uses combustion gases to drive a turbine connected to an electrical generator (NWPCC, 2002 and Alstom Power, 2005).

2. Combined Cycle Gas Turbine (CCGT)

A CCGT is a combination of combustion and steam turbines to generate electricity from two thermodynamic cycles. Exhaust gases from the combustion turbine flow to a heat recovery steam generator that produces steam to power a steam turbine. The use of the waste heat from the combustion turbine, results in a higher thermal efficiency than would be achievable by operating either the combustion or steam turbines individually. Although most of the power comes from the gas turbine (typically 60-70% of the power), the combined power substantially improves the thermal efficiency of the CCGT over a SCGT.

For utility applications, combined-cycle is the usual choice because the steam produced by the gas turbine exhaust is otherwise just wasted. In fact, approximately 75% of all gas turbines are currently being used in combined-cycle plants. The current trend in combined-cycle design is to

use a single-shaft configuration, whereby the gas and steam turbines are on either side of a common generator to reduce capital cost, operating complexity, and space requirements (NREL, 2000; EEA, 2005; and Siemens Westinghouse, 2005).

3. Cogeneration

Cogeneration is the sequential production of electricity and thermal energy from a common fuel source. Excess heat from industrial processes can be used to power an electric generator (bottoming cycle). Conversely, surplus heat from an electric generating plant can be used for industrial processes, or space and water heating purposes (topping cycle).

Cogeneration, also known as combined heat and power (CHP), is the use of a power station to simultaneously generate both heat and electricity. CHP allows more total use of energy than conventional generation, potentially reaching an efficiency of 70-90%, compared with approximately 50% for conventional plants. This means that less fuel needs to be consumed to produce the same amount of energy (SENES, 2003; Brown and Robb, 2005; and Answers.com, 2005).

4. Integrated Gasification Combined Cycle (IGCC)

An IGCC plant uses the same concepts to generate electricity efficiently as a CCGT such that a gas turbine is used to generate electricity, and the waste heat from this turbine is used to raise steam to generate additional electricity via a steam turbine. However, in an IGCC plant, the gas turbine is fuelled by a gas derived from the gasification of liquid or solid carbonaceous materials. IGCC's are able to convert "difficult" liquid and solid fuels to electricity at high efficiencies and with low emissions.

These IGCC plants are typically utilized in emerging advanced coal technologies. They are designed to enhance both the efficiency and the environmental acceptability of coal extraction, preparation and use as an electrical energy fuel source. Examples include ultra supercritical steam cycles, pressurized fluidized bed combustion, and integrated coal gasification combined cycle. The U.S. Department of Energy FutureGen project launched in 2003 is a $1 billion initiative to build an integrated carbon sequestration and hydrogen production research power plant which would be the world's first zero-emissions fossil fuel plant (Amick *et al*., 2002 and EU, 2005).

5. Advanced Gas Turbines

The F-series of gas turbines have been used to characterize gas-fired generation in this report because they are the most common technology used in new installations and there is extensive

operating experience with these units worldwide. Over the past decade, advanced gas turbine combined cycle technologies have been developed and are commercially available from a number of the world's gas turbine manufacturers. These are referred to as G-series and H-series CCGTs. These advanced turbine systems are estimated to have heat rates 12 to 14% lower than the F-series, which results in lower GHG emissions and lower fuel costs. They also have better performance with respect to local air emissions. These units are starting to be built in various international jurisdictions. Operating experience with these units will confirm their performance, reliability and operating costs, and will determine if these advanced systems become the technology of choice in the future (U.S. OFE, 2002). However, given their unproven nature and the lack of readily available information for the G- and H-series, the F-series were used for the purposes of this document.

3.2 NUCLEAR GENERATION OPTIONS

3.2.1 Reactor Description

A variety of nuclear fuel cycles are in use in the world. Currently in Canada, all of the nuclear generation is with the CANDU (Canada Deuterium Uranium) reactor system that uses natural uranium fuel with heavy water as a moderator and as a primary coolant. Normal water (light water), is used in the secondary system to generate electricity via steam generator turbines and to remove waste heat via cooling water. The CANDU reactor is a pressurized system which uses a pressure tube design that allows on-line refuelling.

The CANDU system is a Canadian design developed by Atomic Energy of Canada (AECL). The CANDU system has been utilized in Canada and overseas. AECL has developed an advanced CANDU (ACR); however, the ACR is currently only a design concept. In general terms, the ACR also uses a pressure tube decurrent CANDU systems. The ACR would continue to use heavy water as a moderator and light water as a coolant; however, the fuel would be low-enriched uranium unlike the current CANDU systems but similar to the light water reactors which are in common use throughout the world.

There are two types of light water reactors. They are the PWR (pressurized water reactor) and the BWR (boiling water reactor). The PWR uses light water as a coolant/moderator and enriched uranium as a fuel[1]. It uses a pressure vessel design (all fuel in one vessel rather than in individual pressure tubes as for CANDU's). Power is generated via steam generators/turbines.

[1] Light water moderated reactors require enriched uranium to maintain the nuclear reaction. Currently, enrichment is carried out through either a gaseous diffusion process or a centrifuge process, both of which take advantage of the difference in the weight of an atom of uranium-238 and an atom of uranium-235. In the enrichment process, the ratio of uranium-235 to uranium-238 is increased from the ratio in naturally occurring uranium of about 0.72% to about 4% for use as fuel in light water reactors. As discussed in Dones et al. (2005), the energy demands and consequent environmental effects associated with the two forms of enrichment differ widely.

The BWR is very similar to the PWR except that the boiling water goes directly to the turbines from the reactor. Therefore, during operation, they tend to emit more aerosals than a PWR. The uranium enrichments in commercial light water reactors are about 4% but vary with reactor design.

3.2.2 Nuclear Fuel Cycle

In general terms, the nuclear fuel cycles for all types of reactors have much in common, namely, both the light water and heavy water fuel cycles involve mining, milling, refining, conversion, and waste management. All of the nuclear facilities in Canada are licensed and closely monitored by the Canadian Nuclear Safety Commission. It is recognized that long-term management of spent fuel is a concern to many people. However, all current analyses suggest that the doses to people from waste management are likely to be very small. In any event, there is a national program (see NWMO, 2005) that has the mandate to develop an acceptable method of long term waste management.

Light water fuel cycles also require an uranium enrichment process. Canada has no enrichment capability and enrichment would be carried out at the appropriate facility in the United States, the United Kingdom, France or elsewhere. Finally, several countries, notably the United States, the United Kingdom and France, have used fuel reprocessing facilities to recover uranium and plutonium from irradiated fuel to make new fuels.

Mining

Uranium is recovered from the ground through a variety of mining methods - open pit mines, underground mines and in situ leach operations. In the past, there were a number of mining operations, primarily in Ontario and Saskatchewan (CNUTP, 1987). Although there are potentially developable deposits in a number of provinces and in the territories, all of the existing and currently proposed uranium mining in Canada is in northern Saskatchewan. In Canada, uranium mining is done in accordance with all federal and provincial regulations using both open pit and underground mining methods. Cameco's McArthur River mine[2] is an example of an underground mining operation using advanced mining methods to minimize the radiation exposure to workers. The Cigar Lake mine, also in northern Saskatchewan and currently being readied for development, is another example of an underground high grade uranium mine. Cogema is proposing the development of its Midwest property, also in northern Saskatchewan, as an open pit mining operation. Uranium is also mined through open pit and underground

[2] At the McArthur River mine, located in northern Saskatchewan, uranium ore is extracted underground and transported to Cameco's Key Lake mill for uranium recovery. The footprint of the McArthur facility is quite small with only about 113 ha of the total property of 651 ha considered disturbed. Overall, due to its small footprint and the fact that the ore is shipped offsite for processing, the environmental effects of mining are quite small.

methods elsewhere in the world, sometimes in association with other minerals present in the orebody, for example, the Olympic Dam property in Australia.

In-situ mining involves a uranium ore deposit, often in a sandstone type of material, that is amenable to the extraction of uranium by injecting leaching solutions into the ground and then recovering this solution from a ring of wells surrounding the injection well. Uranium is then extracted from the uranium rich leach solution. In situ leaching of uranium is practiced in the United States and elsewhere in the world, Kazakhstan and Mongolia for example.

Milling

Uranium ore from open pit or underground mining is sent to a uranium mill for uranium recovery. In the mill, the ore is ground and then subjected to an aggressive chemical leaching process followed by uranium recovery. The product of milling is a uranium concentrate usually referred to as yellowcake. At this time, there are three uranium mills in Canada, all of them close together in the Wollaston Lake area of northern Saskatchewan. The sand-like tailings that are left over from the uranium recovery process are sent to a tailings management area for long-term care[3].

Refining and Conversion.

All uranium concentrate from Canadian mines is shipped by truck to Blind River for further purification in a process referred to as refining The Blind River refinery is located on a 275 hectare parcel of land, west of Blind River, ON.

After refining in Blind River, the purified uranium (now in the form of UO_3) is transported to Port Hope in specially designed containers. At the Port Hope Conversion facility, part of the UO_3 is converted to UO_2 to produce fuel for CANDU reactors and the rest is converted to uranium hexafluoride (UF_6) and then transported to the United States or overseas to an enrichment plant. The Port Hope Conversion Facility is located within the municipal boundaries of Port Hope, ON.

Fuel Fabrication

UO_2 powder is then transported to fuel fabrication plants, Zircatec in Port Hope, or General Electric plants in Toronto and Peterborough.

[3] The Key Lake mill, which currently produces uranium concentrate from McArthur River ore, will also in the future produce uranium concentrate from part of the production from the Cigar Lake mine. Ammonium sulphate, a by-product of the milling process, is sold commercially as fertilizer. About 235,000 tonnes per year of new tailings are added to the tailings basin each year. At Key lake, the tailings are managed under a water cover in a below ground pit, which minimizes the footprint of the tailings and the release of radon gas. Overall, the Key Lake mill sits on 3,476 hectares, of which 762 hectares is considered to be disturbed.

3.3 HYDROELECTRIC GENERATION OPTIONS

The evaluation of hydroelectric generation options involved a number of assumptions. The first involved the definition of hydroelectric generation type. With respect to hydroelectric generating stations, there are three basic types:

1. Impoundment – generation involving the installation of a dam and creation of a reservoir including some amount of flooding. Water release for generation may be based on demand (thereby peaking) or for the maintenance of water level downstream.
2. Pumped storage – water is pumped from a lower reservoir to an upper reservoir based on energy demand. This type of station does not always involve the creation of a dammed reservoir.
3. Diversion – water is not impounded into a reservoir, instead it is diverted from the natural water course and passes through some form of channel and through the turbine.

There are a number of generating stations that fall between or are combinations of these three basic types. However, it was assumed for the purposes of this document that the impacts of these intermediate stations would fall between the different types.

With respect to size, the following classifications were made based on those defined by CanREN (Canadian Renewable Energy Network) (www.canren.gc.ca) and the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy (www.eere.energy.gov):

Micro and Mini Hydro → <1MW;
Small Hydro → 1-30MW;
Large Hydro → >30MW.

It was decided that with respect to potential environmental impacts, the largest difference between hydroelectric stations was not by the size, and, therefore, megawatts of electricity produced, but rather by type of station. In particular, environmental impacts were most influenced by whether or not a reservoir would be created. The assumption was also made that there would be no cascading system effects arising from the installation of a number of stations along the same watershed.

For the purposes of this study, the following three different types of hydroelectric stations were evaluated:

1. Impoundment – all stations of this style are assumed to require the creation of a reservoir that will flood some amount of surrounding land. No assumption was made with respect to size.

2. Pumped Storage – assume reservoir creation is minimal and will cause little to no flooding and associated impacts. Assume that peaking impacts are the primary impacts. No assumption is made with respect to size.
3. Diversion – assume no reservoir is created or that it is minimal and will cause little to no flooding and associated impacts. Therefore, the assumption is that no storage of water will occur and that the operation will be run-of-the-river. No assumption is made with respect to size.

3.4 RENEWABLE GENERATION OPTIONS

Since there are a large variety of renewable generation options, a number of assumptions were necessary. First, as indicated in section 1.3, only those technologies that are commercially available and commercially viable at this time were assessed. A number of technologies show promise but are either too small in power generated or not yet commercially viable for consideration in this study. A number of technologies were reviewed in this study:

Photovoltaic (PV) Systems

PV systems directly convert the energy from the sun into electricity using different semiconductor devices such as crystalline silicon wafers and thin films. An inverter is used to convert the low voltage direct current to higher voltage alternating current. According to CanREN (2002a), PV systems are generally suited for low power situations in more remote areas not connected to the power grid, such as telecommunications repeater stations, navigational aids, laptop computers and cottages. The advantage to PV systems is that they use a renewable form of energy (sunlight), they don't produce noise and the use of PV systems has virtually no impact on the air, land or water. One important disadvantage is that they can only be used in low power situations and, at present, cannot provide an appreciable amount of power. A second disadvantage is the lack of appropriate energy storage systems for large scale use of PV at times when solar insulation is low or non-existent.

PV systems are a new and emerging technology. The energy requirements needed to produce present-day crystalline silicon vary considerably depending on wafer thickness and the silicon feedstock that is used. These energy requirements are projected to decrease over time because of better feedstock, expected decreases in the amount of feedstock required to produce a cell and efficiencies in manufacturing. PV is similar to wind in that most of the environmental impacts are generated during the production phase. As technology rapidly advances, these impacts are being reduced. As well, the environmental impacts are also related to the type of electrical generation used to produce the PV systems. Newer technology is less polluting and thus newer PV systems have a smaller environmental impact. In a paper produced for the 31st IEEE

Photovoltaic Specialists Conference (Fthenakis *et al*., 2005), there was limited or no recent life cycle environmental data available for Crystalline Si Photovoltaics or Thin-Film Photovoltaics.

Absorption Cooling

An absorption chiller is connected to high-temperature collectors such as vacuum tubes or concentrating collectors. The absorption chiller operates in a temperature range of 80 – 120ºC. According to CanRen (2002b), this type of chiller requires some electricity for pumping, has limited efficiency, and requires advanced solar collectors. This system was not evaluated further in this study.

Fuel Cell Systems

Fuel cells convert chemical energy directly into electricity. Hydrogen-rich fuel is directed to an anode while an oxidant is directed to a cathode. The oxidant used is generally air. The porous anode and cathode conduct electricity. They are situated on either side of a non-conducting electrolyte material. Ionization occurs because of the chemical affinity of hydrogen for oxygen and the electrically charged ions pass from one electrode to the other through the electrolyte, which selectively permits ions to move through the material and react with gas on the other side. Voltage is produced through the build-up of electrons on the anode. The by-products of the electrochemical conversion are heat, carbon dioxide and water. The heat is used to free hydrogen and produce CO from a wide range of hydrocarbon fuels (such as natural gas) in a fuel processing step. In the fuel cell, the electrodes and electrolytes are sandwiched between plates that direct fuel and oxidants and electrically connect the cells into stacks. The direct current produced is converted into alternating current.

There are efficiency gains to fuel cell use since there will be no electricity lost through long transmission lines and the waste heat can be used for heating, ventilation and air conditioning (HVAC) of large buildings. However, due to the newness of the technology, data on the environmental impacts during the manufacturing stage and the decommissioning stage are not readily available.

Current fuel cell capital costs range upwards of $4,000.00 per kilowatt. To ensure entry into mainstream power markets, costs will need to reach $400.00 per kilowatt-hour. (U.S. OFE, 1995). A great deal of research and development is being undertaken, primarily in the United States, however, at the present time, this technology is not commercially viable. According to the U.S. Department of Energy, the clean nature of fuel cells, however, has led to 26 states offering financial incentives to support the installation of fuel cells and there are major fuel cell programs being developed in New York, Connecticut, Ohio and California.

Wind Turbine Systems

Wind turbines convert the kinetic energy that is present in moving air into electricity. The amount of electricity produced is directly related to wind speed and the density of the air (which is determined by air temperature, barometric pressure and altitude).

The use of wind energy is growing world-wide. As a result of demand for wind turbines and engineering improvements, the costs per kilowatt hour are becoming more competitive with other generation types.

A wind turbine consists of six major components (NRC, 2002c):

- A rotor that aerodynamically converts the wind energy into mechanical energy on a slowly rotating shaft;
- A gearbox that increases the rotor shaft speed for the generator;
- A generator that produces electricity;
- A control and protection system that optimizes performance and keeps the machinery operating within safe limits;
- A tower that elevates the rotor off the ground to an elevation where wind speed is greater; and
- A foundation that supports the wind turbine system.

Aside from the raw material and energy cost associated with production of these components, wind energy is considered to be pollution free and infinitely sustainable. It doesn't create greenhouse gasses and it doesn't produce toxic or radioactive waste.

An initial assessment of 2-blade versus 3-blade rotors was undertaken. In discussions with a representative of one of the major turbine manufacturers, it was determined that the 2-blade is no longer a popular design. This was further verified by ECLIPSE (2004) in their overview report which stated "The technologies studied in ECLIPSE were chosen in order to be representative of the most widely used wind turbines. Therefore, 2-blade wind turbines and vertical axis wind turbines were not examined..."

3.5 OMI PROJECT

An assessment of high voltage electric transmission was excluded from the original scope of the consulting assignment. However, a subsequent request was made by the OPA for SENES to include an assessment of the OMI Project.

The OMI project was originally planned to take power from a proposed Manitoba Hydro generating station (Conawapa) on the Lower Nelson River via a new 1,180 kilometre long high voltage direct current transmission line in Manitoba which connected to a new 500 kV alternating current transmission line from the inter-provincial border that would cross northwestern Ontario and much of northeastern Ontario and tie into Hydro One's bulk electrical system at Timmins. The project was terminated in the early 1990s by the government of Ontario. In 2003 Hydro One and Manitoba Hydro initiated a study to determine the feasibility of a large-scale sale and delivery of hydroelectric power from Manitoba to Ontario. The feasibility study has now been completed and a decision on proceeding is pending.

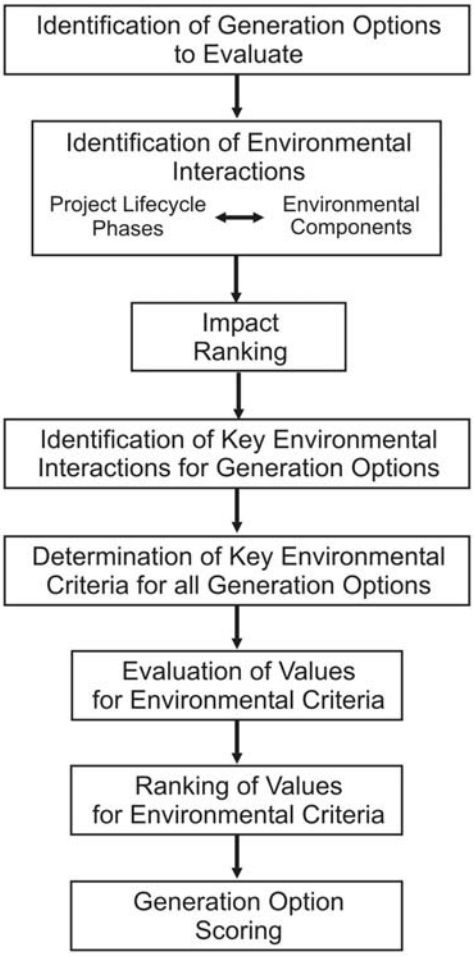
It is SENES' understanding that new alternatives have been identified that include up to 2,500 kilometres of new transmission line. However, because Manitoba Hydro views the OMI Project as an opportunity to strengthen its own system, it is difficult to assess the impacts of the entire transmission line as being attributable to Ontario. Further, the alternatives presented are not the most direct routes.

4.0 IDENTIFICATION OF ENVIRONMENTAL INTERACTIONS

In order to develop the evaluation methodology, SENES assembled a team of staff with a range of technical expertise. These individuals have experience in conducting environmental assessments of nuclear, hydroelectric, thermal and wind power facilities. It was considered important to have a range of technical expertise available to the study team in order to try and ensure that, within study constraints, the analysis would consider as broad a range of impacts as possible and a wide range of opinions concerning the various alternative technologies.

The team met at key points in the development of the methodology in order to agree on the approach and focus the next steps. Individual members could then be tasked with different generation options or environmental criteria to evaluate according to expertise. Figure 4.1 provides an overview of the methodology that is presented in the subsequent subsections and chapters.

FIGURE 4.1
OVERVIEW DIAGRAM OF THE IMPACTS TO THE NATURAL ENVIRONMENT FROM GENERATION OPTIONS METHODOLOGY


Identification of Generation Options to Evaluate
Identification of Environmental Interactions
Project Lifecycle Phases
Environmental Components
Impact Ranking
Identification of Key Environmental Interactions for Generation Options
Determination of Key Environmental Criteria for all Generation Options
Evaluation of Values for Environmental Criteria
Ranking of Values for Environmental Criteria
Generation Option Scoring

4.1 PROJECT LIFECYCLE PHASES

The first step in determining the potential impacts of each generation option involved the identification and assessment of the interaction between project phases and components of the natural environment. In order to capture the basic lifecycle of each type of generating station, seven phases were identified:

1. Resource Extraction – this phase was intended to capture the physical removal of the energy source. For example, the mining of uranium and coal and the drilling of natural gas. As the project evolved, this stage also came to capture any manufacturing impacts.
2. Processing – this phase was intended to capture any secondary treatment that may be required to bring the extracted resource to a useable state. For example, the processing of uranium ore to fuel rods and the refining of raw natural gas to a refined natural gas product.
3. Transport – this phase was intended to capture the environmental costs of transporting the fuel source from extraction through to the generating station. For example, the transport of coal from the mine site through to the thermal generating station.
4. Construction – this phase was intended to capture all impacts related to the construction of the generating facility as well as any associated facilities. For example, a hydroelectric station would capture the construction of a dam as well as the reservoir creation and the powerhouse construction.
5. Operation – this phase was intended to capture the environmental impacts that would arise from the actual operation of the generating station and production of energy. For example, the air and once-through cooling water from a nuclear generating station. It was anticipated that this phase would involved the most important environmental impacts.
6. Accidents & Malfunctions – this phase was intended to capture the environmental impacts of any accidents, malfunctions or irregular operations. This phase was not intended to capture low probability events, for example a nuclear accident or the failure of a large hydroelectric dam. However, it would capture events such as unplanned spilling at a hydroelectric facility.
7. Decommissioning – this phase was intended to capture the environmental impacts of generating station decommissioning and the removal of all associated facilities. For example, the footing and structure removal as well as land reclamation at a wind farm.

4.2 ENVIRONMENTAL COMPONENTS

Following the identification of project phases, a comprehensive list of environmental components was identified. This list was generated from previous work completed by SENES as well as by reviewing provincial, federal, scientific and industry documents for identified environmental impacts of generation (Beanlands and Duinker, 1983; EC, 1981; NRC, 2004; Ontario Hydro, 1988; Ontario Hydro, 1990; Ontario Hydro, 1989a; Ontario Hydro, 1989b; ME,

2001; MNR, 2003; and State of Hawaii 1995). The following are the environmental components and subcomponents identified for evaluation:

1. Regulatory Approval Required – a simple component to indicate whether the project phase would require regulatory approval. The assumption was made that all projects/alternatives would meet or exceed currently applicable regulatory requirements
2. Resource Use – another simple component to indicate whether the project phase would involve renewable or non-renewable resources.
3. Atmospheric Environment
    i. Air Quality – a subcomponent to identify potential impacts from air emissions such as NO_x, SO_x, greenhouse gases, particulate matter, etc.
    ii. Noise – a subcomponent to identify potential impacts from noise.
    iii. Microclimate – a subcomponent to identify any potential impacts that a generation option may have on the local climate.
    iv. Potential for Cumulative Impacts – a subcomponent to identify whether cumulative impacts are expected between this component and other projects or components.
4. Public
    i. Public Health and Safety for Humans – a subcomponent to identify potential project impacts on the safety and health of workers or the public.
    ii. Potential for Cumulative Impacts – a subcomponent to identify whether cumulative impacts are expected between this component and other projects or components.
5. Geology and Hydrogeology
    i. Geology – a subcomponent to identify any potential project impacts on geology (landforms and bedrock).
    ii. Soil – a subcomponent to identify any potential project impacts on soil (unconsolidated surface layer of the land).
    iii. Groundwater Quality, Quantity and Flow – a subcomponent to identify any potential project impacts on local or regional groundwater due to changes in elevation or path, or through contamination.
    iv. Potential for Cumulative Impacts - a subcomponent to identify whether cumulative impacts are expected between this component and other projects or components.
6. Hydrology and Surface Water
    i. Hydrology – a subcomponent to identify any potential changes to the local hydrograph, particularly seasonal and daily water level fluctuation.
    ii. Surface Water Quantity – a subcomponent to identify any potential effects on surface water quantity due to use.

iii. Potential for Cumulative Impacts - a subcomponent to identify whether cumulative impacts are expected between this component and other projects or components.

7. Aquatic Environment
    i. Surface Water Quality– a subcomponent to identify any potential effects on surface water quality through contaminant introduction or changes to the physical characteristics, specifically as these impacts relate to the aquatic biology.
    ii. Sediment Quality and Quantity Including Shoreline – a subcomponent intended to identify potential impacts on the benthic sediment and shoreline of any water body.
    iii. Aquatic Biota – a subcomponent specifically intended to identify potential impacts on the biology of the aquatic environment, such as through entrainment or impingement.
    iv. Species at Risk – a subcomponent intended to assess potential impacts to identified aquatic species at risk.
    v. Protected Areas – a subcomponent intended to identify specific impacts to identified aquatic protected areas.
    vi. Aquatic Habitat – a subcomponent to identify the potential for impacts to aquatic biota habitat.
    vii. Navigation – a subcomponent to identify potential impacts to navigation on water bodies.
    viii. viii. Potential for Cumulative Impacts - a subcomponent to identify whether cumulative impacts are expected between this component and other projects or components.
8. Terrestrial Environment
    i. Vegetation Communities and Species – a subcomponent intended to identify potential impacts on the vegetation in the area.
    ii. Species at Risk – a subcomponent to identify specific impacts to identified terrestrial species at risk.
    iii. Protected Areas – a subcomponent intended to identify potential impacts to identified terrestrial protected areas.
    iv. Wildlife Habitat – a subcomponent to identify the potential impacts on terrestrial wildlife habitat.
    v. Wildlife Communities and Species – a subcomponent to identify potential impacts to terrestrial wildlife.
    vi. Potential for Cumulative Impacts - a subcomponent to identify whether cumulative impacts are expected between this component and other projects or components.

9. Land Use
    i. Land Use – a subcomponent to identify potential impacts on the human use of land.
    ii. Landscape and Visual Setting – a subcomponent to identify impacts to the local aesthetic value.
    iii. Archaeological Sites – a subcomponent to identify impacts to any site of potential archaeological importance and the ability to access those sites.
    iv. Traditional Land and Resource Use – a subcomponent specifically to address loss of aboriginal use of land or resources due to development.
    v. Potential for Cumulative Impacts - a subcomponent to identify whether cumulative impacts are expected between this component and other projects or components.
10. Waste Material Generation
    i. Solid Waste – a subcomponent to identify the production of solid waste.
    ii. Aquatic Effluent – a subcomponent to identify the production of liquid effluent.

The interaction table that was utilized to assess the potential interaction between generation option life-cycle components and these environmental components is provided as Table A1 in Appendix A.

4.3 IMPACT RANKING

Following the identification of project activities for each life-cycle phase and the environmental components and subcomponents, a professional judgement evaluation was made by the team to determine the magnitude of impact on the natural environment component from the project activity. The following provides the rating used for this evaluation:

- Nil – The environmental component is clearly not affected by the project activity.
- Low – There is a high degree of certainty that the environmental component will be minimally affected by the project activity. Any species effects will be at the individual level and will occur only over a short period of time with no impact on any dependent species or populations.
- Medium – There is reasonable certainty that the environmental component may be significantly impacted by the project activity. Any species effects will only occur to a portion of the population, either with respect to abundance or distribution, and will be limited to less than two generations with no threat to any dependent species populations.
- High – There is a high degree of certainty of significant impacts or a low level of certainty and therefore more evaluation or mitigation measures must be investigated to the environmental component from the project activity. Any species effects occur at the population level and are greater than what natural recruitment can compensate or they will threaten the population of a dependent species.

- Unknown – The potential effects on the environmental component from the project activity is not known.

These ratings were adapted from Beanlands and Duinaker, 1983. Although these ratings were done primarily from professional experience, they also utilized various published information sources specific to the type of generation.

5.0 IDENTIFICATION OF KEY ENVIRONMENTAL INTERACTIONS FOR GENERATION OPTIONS

Following the general ratings developed in section 4.3, the most relevant and important environmental subcomponents were identified for each generation type. These environmental subcomponents identified for the generation type were deemed significant enough to provide comparison of environmental impact of the generation versus other generation types.

5.1 THERMAL GENERATION OPTIONS

A life-cycle view of the impacts of the impacts associated with thermal generation options pose challenges and constraints with quantifying "upstream" and "downstream" impacts at each life-cycle stage. Some examples of the type of issues associated with life-cycle impacts for thermal generation options include:

- Upstream greenhouse gas emissions from natural gas production and distribution activities (e.g., fugitive gas emissions);
- Upstream land impacts from natural gas and coal production and distribution activities;
- Wood waste biomass upstream benefits from displacing emissions from beehive burners; and
- Biomass transportation emissions;

5.1.1 Thermal Generation Key Environmental Components

The important environmental subcomponents identified for all thermal generation styles were:

- Air Quality;
- Soil;
- Aquatic Biology;
- Surface Water Quantity;
- Surface Water Quality;
- Wildlife Communities and Species;
- Land Use;
- Wildlife Habitat.

5.2 NUCLEAR GENERATION OPTIONS

For the general impacts of nuclear generation, the four alternatives identified in section 3.2 were considered to have the same natural environment impacts. However, the evaluation of the

nuclear options assumed that impacts were being evaluated based on best management practice mitigation measures.

Within the natural resource criteria used for evaluation, the evaluation of air emissions, and surface water quantity and quality included both the radioactive and non-radioactive components.

5.2.1 Nuclear Generation Key Environmental Components

The important environmental subcomponents identified for all nuclear generation options were:

- Public Health and Safety for Humans;
- Air Quality;
- Aquatic Biology;
- Surface Water Quantity;
- Surface Water Quality;
- Land Use;
- Wildlife Habitat;
- Solid Waste.

5.3 HYDROELECTRIC GENERATION OPTIONS

For hydroelectric generation life-cycle analysis using the interaction matrix, no resource extraction or processing project elements were considered.

5.3.1 Hydroelectric Generation Key Environmental Components

The important environmental subcomponents identified for all hydroelectric generation options were:

- Hydrology;
- Aquatic Habitat;
- Aquatic Biology;
- Landscape and Visual Setting;
- Traditional Land and Resource Use;
- Wildlife Habitat;
- Wildlife Communities and Species;
- Air Quality;
- Groundwater Quality, Quantity and Flow;

- Soil;
- Sediment Quality and Quantity Including Shoreline;
- Surface Water Quantity;
- Land Use.

5.4 RENEWABLE GENERATION OPTIONS

5.4.1 Renewable Generation Key Environmental Components

For wind generation, the important generation subcomponent identified was:

- Landscape and Visual Setting

It should be cautioned that even though only one key environmental component was identified for wind power as a generation option, this does not imply that wind generation is benign with respect to environmental impacts. Wind generation will undergo the same analysis as all potential generation options and will be scrutinized alongside each.

Neither photovoltaic nor fuel cell generation options were included in the original environmental interaction matrix analysis. No key environmental components were identified for these generation options; however, they will be included in subsequent analysis where applicable.

5.5 OMI PROJECT

Since the OMI Project was not included in the original environmental interaction matrix exercise, key components were not identified. However, comparison of similarities of potential environmental interactions between generation and transmission follows.

The environmental characteristics of a transmission line are significantly different than that of a generating station. In the case of the OMI Project, land, water and air impacts will occur over a distanceof more than 2,000 kilometers, while the natural environment impacts of a generating station are primarily local (with the exception of dispersion of air emissions and upstream/downstream effects of water use). Because a new generation station will be required on the Nelson River to support the transmission line, the environmental impacts of this station must be factored into the total environmental impact of the OMI Project.

Natural environment impacts of a high voltage transmission line occur during construction (right-of-way clearing, constructing access roads, preparing the tower foundations, tower assembly and stringing the conductors), operation (right-of-way maintenance, EMF issues) and

decommissioning (tower disassembly and removal). They fall into the same general categories as the generation options (impacts to air, human health & safety, land and water) and the magnitude of the impact tends to increase with the length of the line.

In terms of a life-cycle assessment, the raw materials that create a transmission tower are similar to those found in a tower used for wind power generation. The number of transmission towers, however, in over 2,000 kilometres is difficult to predict since this will depend upon system design (ac versus dc, average span, topography, etc.) There could be well over 3,000 towers, depending upon various engineering considerations.

A 2002 publication by the National Institute of Environmental Health Sciences and the National Institutes of Health in the U.S. surveyed research on EMF exposure to humans in various countries around the world. In general, no link between high voltage electric transmission facilities and health issues has been substantiated. In December, 1998, a working group of public health officers at Health Canada issued a review of the scientific literature regarding power-frequency EMF health effects. They found the evidence to be insufficient to conclude that EMF causes a risk of cancer (NIEHS, 2002). The live power lines are well removed from human contact. With proper training in working around power lines, maintenance workers rarely experience burns or fatalities.

While the actual land required for the towers ranges from 30 metres for a V-guyed 500 kV dc tower to 36 metres for a similar ac tower, the amount of cleared right-of-way required ranges from 70 to 80 metres. The land requirement for the transmission line would thus be rouhgly 150 square kilometers of cleared land. Since most of the land is forested, it would result in the destruction of a great deal of natural habitat and the permanent removal of the forest cover from the right-of-way, taking it out of production and thus impacting upon forest sustainability.

6.0 DETERMINATION OF KEY ENVIRONMENTAL CRITERIA

Chapter 4 set out life-cycle components for all possible generation options and Chapter 5 set out all possible environmental components for each generation option. The detailed analysis used in the initial interaction matrix could not be translated completed into the final document and generation option comparison. Decisions were made to determine which components of the generation life-cycle and the environment were key to the subsequent comparison of different generation options were carried forward.

6.1 ENVIRONMENTAL COMPONENTS FOR GENERATION OPTION COMPARISON

While each of the environmental components and subcomponents were seen as important, it was clear that some were more important, especially with respect to highlighting differences between the potential environmental impacts of generation options. To insure that all factors that would be considered in a full environmental assessment were considered in our analysis, a comprehensive approach was taken in the initial environmental interaction matrix. From the beginning of this process to develop a method to compare generation options, it was clear that inclusion of all environmental components identified would make the methodology cumbersome and impossible to evaluate. Further, many of the components involve information that is only available on a site specific basis or is generated specifically during consideration of generation alternatives siting.

Below is a list of the components that were evaluated and reasons why, or why not, they were considered for further development into the final criteria for generation option comparison. Note that the key environmental subcomponents that were identified for each generation type in Chapter 5 are bolded:

1. Regulatory Approval Required – It was decided that not only did all generation options require some level of approval; this component would be identified in a site specific analysis. Further, although some generation options require more extensive approval processes, this is not really a natural environment impact.
2. Resource Use – This component would be incorporated into the sustainability criterion.
3. Atmospheric Environment
    i. **Air Quality** –It was decided that this factor was important for every generation option except renewable. Therefore, it was determined that not only should it be kept, but it should be split into the component emissions that actually cause effects.

ii. Noise – As an environmental component, noise was determined to be a site specific impact thus mitigated at the siting stage. Consequently, noise was eliminated as a criterion for generation option comparison.
iii. Microclimate – It was determined that this subcomponent had limited relevance to localized climate regimes and, therefore, was too site specific to be useful in generation option comparison.
iv. Potential for Cumulative Impacts – Any cumulative impacts would be site specific and, therefore, could not be broadly evaluated in this study.

4. Public
   i. **Public Health and Safety for Humans** – While SENES recognized that this factor was exceptionally important, it was decided that most of the recognized impacts resulted from air quality factors and that these would be included in the Air Quality discussion.
   ii. Potential for Cumulative Impacts – Any cumulative impacts would be site specific and, therefore, could not be broadly evaluated in this study.
5. Geology and Hydrogeology
   i. Geology – As an environmental component for comparison, it was decided that geological impacts of most generation options were relatively minor and would not be useful for determining differences between options.
   ii. **Soil** –While soil was important for more than one generation option, it was decided that it was too site specific and that general effects could be included in the definition of another subcomponent.
   iii. **Groundwater Quality, Quantity and Flow** –Impacts to groundwater were deemed to be quite site specific. Further, it was decided that no generation option caused groundwater impacts at every possible site. Therefore, this environmental subcomponent, while deemed important, was not carried forward as a comparison criterion.
   iv. Potential for Cumulative Impacts - Any cumulative impacts would be site specific and, therefore, could not be broadly evaluated in this study.
6. Hydrology and Surface Water
   i. **Hydrology** –While hydrology was identified as perhaps the largest impact of hydroelectric operations, it was decided that this effect would be included in another criterion.
   ii. **Surface Water Quantity** –This factor was important for every generation option except renewable and it was decided that it could be defined to encompass other important impacts; therefore, it was decided that it should become part of the comparison criteria.
   iii. Potential for Cumulative Impacts - Any cumulative impacts would be site specific and, therefore, could not be broadly evaluated in this study.

7. Aquatic Environment
    i. **Surface Water Quality** – As an environmental criterion, surface water quality was deemed important but the definition was reworked for use as part of a comparison criterion.
    ii. **Sediment Quality and Quantity Including Shoreline** – This factor was important only for hydroelectric generation impacts and was relatively site specific; therefore, it was not included in the final criteria for comparison.
    iii. **Aquatic Biota** – While it was recognized that aquatic biology impacts were important for every generation option except renewable, it was decided that these impacts could be included in the definition of another comparison criterion.
    iv. Species at Risk – It was determined that impacts to aquatic species at risk were really a site specific component that would be dealt with at the siting and environmental assessment level.
    v. Protected Areas – The identification of protected areas was deemed too site specific for further consideration as a comparison criterion.
    vi. **Aquatic Habitat** – As an environmental component, aquatic habitat was only considered an important factor for hydroelectric as a generation option. Further, it was decided that it was really a site specific factor. As such, this environmental subcomponent was not included in the comparison criteria.
    vii. Navigation – This component was not only considered site specific but, it would require mitigation at the environmental assessment stage.
    viii. Potential for Cumulative Impacts - Any cumulative impacts would be site specific and, therefore, could not be broadly evaluated in this study.
8. Terrestrial Environment
    i. Vegetation Communities and Species – This environmental component was identified as being site specific in effects and typically would require mitigation at the siting stage of evaluation.
    ii. Species at Risk – It was determined that impacts to terrestrial species at risk were really a site specific component that would be dealt with at the siting and environmental assessment level.
    iii. Protected Areas – The identification of protected areas was deemed too site specific for further consideration as a comparison criterion.
    iv. **Wildlife Habitat** – While wildlife habitat was considered an important subcomponent, it was decided that it could be included in the definition of other comparison criteria.
    v. **Wildlife Communities and Species** – It was decided that the potential impacts of generation options to wildlife communities and species was really a site specific impact; therefore, could not be readily used to compare generation options in a broad manner.

vi. Potential for Cumulative Impacts – Any cumulative impacts would be site specific and, therefore, could not be broadly evaluated in this study.

9. Land Use
    i. **Land Use** –This factor was considered important for all generation options except renewable. As such, it was included as a comparison criterion with an expanded definition.
    ii. **Landscape and Visual Setting** – While this environmental factor was considered the only important environmental subcomponent for wind generation, it was decided that it could be included in another comparison criterion.
    iii. Archaeological Sites – This component was deemed to be site specific; therefore, not amenable to inclusion as a comparison criterion.
    iv. **Traditional Land and Resource Use** – This criteria, while deemed important, was considered too site specific to be included in the general comparison criteria that would be used to evaluate different generation options.
    v. Potential for Cumulative Impacts - Any cumulative impacts would be site specific and, therefore, could not be broadly evaluated in this study.
10. Waste Material Generation
    i. **Solid Waste** – Solid waste as an environmental criterion was deemed important but the definition would be reworked for use as a comparison criterion.
    ii. Aquatic Effluent – While this component was identified as a potentially important criterion, it was decided that the associated impacts would be incorporated into another comparison criterion.

6.2 FINAL EVALUATION CRITERIA

New comparison criteria were developed to encompass the important, non-site specific environmental subcomponents. These developed criteria were as follows:

- Air Impacts – these criteria are intended to create a composite that will act as a proxy for the impacts identified previously under the subcomponents Air Quality and Public Health and Safety for Humans.
    - Contaminant Emissions – compared as kilograms per megawatt hour. This criterion will include emissions of NO_x, SO_2, PM_{10}, and hazardous air pollutants with weighting appropriate to potential human health effects. At least one hazardous air pollutant will be included for each fuel or option including mercury and radioactivity.
    - Greenhouse Gas Emissions – compared as kilograms per megawatt hour. This criterion includes the primary greenhouse gas emissions – CO_2, CH_4 and N_2O weighted for global warming potential.

  - Radiological Emission – compared as a normalized collective effective dose (person Sv/GW a). This criterion considers all radiological effects on a local population basis.
- Land Impacts – this criterion was intended to provide an approximation for the impacts identified previously under the subcomponents Land Use, Soil, Wildlife Habitat, Landscape and Visual Setting and Traditional Land and Resource Use.
  - Land Use – compared as area per megawatt hour. This criterion includes not only changes or loss of total land but also negative impacts to terrestrial habitat.
- Water Impacts – this criterion is intended to act as a proxy for the impacts identified previously under the subcomponents Aquatic Biology, Surface Water Quality and Quantity and Hydrology.
  - Water Use – compared as volume per megawatt hour. This criterion includes not only use but, potential changes to physical characteristics such as temperature and dissolved oxygen and the potential impacts to surface water from changes in daily and seasonal releases. These impacts also include biological and physical water body impacts from changes in total water volume and elevation.
- Waste – these criteria are intended to include impacts identified previously under the subcomponents Solid Waste and Aquatic Effluent.
  - Extraction Waste – This criterion is intended to include the generation of waste during the physical removal of the energy source.
  - Operational Waste – reported as either tonnes or volume per megawatt hour (for solid and liquid waste respectively). This criterion is intended to include all waste generated during station operation.
  - Decommissioning Waste – this criterion is intended to include waste generated during the decommissioning of a generation facility including all associated facilities.
- Sustainability – this criterion is intended to identify whether the fuel used during generation is renewable or not and as such will measure resource depletion. Owing to the nature of the criteria, that only the fuel was assessed, sustainability was not evaluated for life-cycle stages but for each generation option as a whole.

6.3 LIFE-CYCLE COMPONENTS FOR GENERATION OPTION COMPARISON

The initial identification of life-cycle components was comprehensive and exhaustive for each generation option. However, it was determined that although some excellent studies existed that had previously examined generation option life-cycles, see in particular the series of ExternE reports (http://externe.jrc.es/reports.html), there was a lack of readily available information for many life-cycle stage impacts for many generation options. Identified below are the life-cycle stages and their corresponding evaluation criteria that were carried forward in this study.

1. Resource Extraction – This life-cycle stage was formally evaluated for Air Impacts and qualitatively for Waste. No information was readily available for Land Impacts or Water Impacts.
2. Processing – This life-cycle stage was formally evaluated for Air Impacts and qualitatively for Waste as part of the overall mining impacts discussion. Information was not readily available to evaluate Land Impacts or Water Impacts although these are expected to be minimal, and limited to thermal and nuclear options.
3. Transport – No information was readily available for any generation option or evaluation criteria. Further, much of the impact would be relatively site specific depending on travelling distances. As such, no evaluation was completed for this life-cycle stage.
4. Construction – This life-cycle stage was not formally evaluated for any evaluation criteria primarily because it was determined that impacts were expected to be similar for all generation options.
5. Operation – This life-cycle phase was formally evaluated for all evaluation criteria.
6. Accidents & Malfunctions – This life-cycle phase included unplanned spills, releases, fires or mechanical failures but, was not formally evaluated for any evaluation criteria. During completion of the interaction matrix, we determined that only those events not considered rare with exceptionally low probability of occurrence would be included in the life-cycle phase. It was further determined that any unplanned spills or releases, for example spilling at a hydroelectric station, would be site specific to a generation facility and would be dealt with in the planning stage of the environmental assessment.
7. Decommissioning – This life-cycle phase was only qualitatively evaluated for Waste. Other impacts from decommissioning are expected to be minimal and either site specific in nature or similar across all generation options and therefore not useful as an evaluation criteria.

7.0 ENVIRONMENTAL CRITERIA VALUES

7.1 AIR IMPACTS

In order to evaluate potential air impacts of alternate energy technologies, it was necessary to develop an approach that allowed for comparison of vastly different technologies. In the end, it was decided that it would be reasonable to develop a comparison framework based on potential for human health effects or a surrogate for this factor. In order to do this, it was necessary to make a number of assumptions, including,

- Any technology to be developed would be designed to modern standards and meet or exceed all relevant emissions and air quality standards;
- Existing air quality standards used in this analysis are based on, or reasonable surrogates for, potential human health effects;
- That there is a definable relation between emissions to the air and ambient concentrations of the emissions.; and
- That for radioactive emissions from nuclear reactors, there is a well defined relation between the dose arising from such emissions and potential health effects.

7.1.1 Air Methodology Overview

There is a well defined relationship between air emissions and ambient concentration arising from such air emissions[4], therefore, the key consideration for this evaluation is air emissions associated with the life cycle of each of the candidate alternative energy technologies.

For many technologies, emission estimations are based on the standard U.S. EPA emission reference known as AP-42 (U.S. EPA 1995). In applying the emission factors, where controls were available, it was assumed that these would be applied and sources would meet New Source Performance Standards (NSPS). AP-42 emission factor information was supplemented with available documents such as national emission inventories, and technical papers reporting on Life Cycle Analysis. The European Commission has conducted an extensive research study (beginning in 1991) of the externalities for electrical power generation (Externalities of Energy – ExternE). Reports from 13 participating countries are posted on the web site http://externe.jrc.es/reports.html. Where data was not readily available from typcial emission factor sources, such as AP-42, the ExternE reports were a valuable resource.

For coal and natural gas combustion sources, AP-42 provides pollutant emission rates based on fuel throughput. Therefore, typical fuel heat ratings, and unit efficiencies for each technology

[4] Such relations are well defined through the use of air dispersion models such as those used and approved by the US EPA (http://www.epa.gov/ttn/scram/)

were used to develop emission rates for each pollutant on a power production basis (i.e. kg/MWh) for a range of turbine efficiencies.

Internationally, much published data is available concerning emissions from nuclear reactors and consequent doses. The most recent report of the United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR 2000) which has the United Nations mandate for sources and effects of ionizing radiation, is a prime source of information on the radiological aspects of the nuclear fuel cycle, including nuclear generating systems. In evaluating radiological impacts from the nuclear fuel cycle, UNSCEAR bases their analysis on global collective dose. While noting that doses vary from facility to facility, UNSCEAR also notes that individual doses "decrease markedly" with increasing distance. For the present assessment, the principle comparisons are also based on UNSCEAR's concept of collective dose. However, since this concept involves the integration of small individual doses over large areasand long time frames (in some instances, up to 10,000 years), some additional observations concerning doses to the most exposed individuals namely those living proximate to a nuclear facility, are also provided.

7.1.1.1 Contaminant Emissions

The primary human health related pollutants considered are nitrogen oxides (NO_x), sulphur dioxide (SO_2), fine particles (PM_{10}), hazardous air pollutants (HAPs). To normalize the pollutants emissions, contaminant weighting factors were developed:

- Available annual average human health based air quality criteria were used for the acid gases and particulate
  - NO_x – Environment Canada Maximum Acceptable Level (National Air Quality Objectives) (Environment Canada 2003) 100 $\mu g/m^3$, was a assigned a weighting of 1.
  - SO_2 – Ontario MOE Annual Ambient Air Quality Criteria (MOE 2001) – 55 $\mu g/m^3$; weighting of 100/55 = 1.8.
  - PM_{10} – U.S. EPA National Ambient Air Quality Standards (U.S. EPA 2005a) – 50 $\mu g/m^3$; weighting of 100/50 = 2.
  - $PM_{2.5}$ – U.S. EPA National Ambient Air Quality Standards (U.S. EPA 2005a) – 50 $\mu g/m^3$; weighting of 100/15 = 6.7.
- Reference concentrations were used for hazardous air pollutants (HAP). Several "screening" HAPs were selected based on the constuents with the highest emission rate relative to its reference concentration or risk value:
  - Benzene - U.S. EPA Integrated Risk Information System (IRIS) (U.S. EPA 2005b) $1x10^{-5}$ risk level for inhalation is 1.3 $\mu g/m^3$; weighting 100/1.3 = 77.
  - Formaldehyde - U.S. EPA IRIS (U.S. EPA 2005b) $1x10^{-5}$ risk level for inhalation is 0.8 $\mu g/m^3$; weighting 100/0.8 = 125.

- Mercury - U.S. EPA IRIS (U.S. EPA 2005b) inhalation RFC is 0.3 $\mu g/m^3$; weighting 100/0.3 = 333.

Normalized pollutant emission values were summed for each fuel/technology combination to determine an overall emission value that can be used to compare different technologies

7.1.1.2 Radioactivity Emissions

Various radionuclides are released from nuclear fuel cycle activities. Radon emissions are the main air emission from mining and milling. Air emissions from refining, conversion and fuel fabrication are primarily uranium isotopes. The radionuclides released from nuclear reactors vary by type of reactor and from reactor to reactor but include such species as noble gases, radioactive particulate and tritium. Fortunately, well accepted methods exist for converting exposure to any radionuclide to a common unit, namely dose (see for example UNSCEAR 2000, ICRP 60 1990). Radioactive emissions and normalized collective doses from the nuclear fuel cycle are reported by UNSCEAR 2000, and UNSCEAR 1993.

7.1.1.3 Greenhouse Gas Emissions

Although not directly related to potential health effects, greenhouse gas emissions (GHGs) are of great interest and it is considered important to include them in a comparative evaluation of alternative energy technologies.

The primary greenhouse gas (GHG) emissions are: carbon dioxide (CO_2); methane (CH_4) and nitrous oxide (N_2O). Greenhouse gas emissions were converted to total CO_2 equivalents based on the global warming potential (GWP) of each constituent:

- $CO_2 = 1$
- $CH_4 = 21$
- $N_2O = 270$

7.1.2 Natural Gas Fuel Cycle

7.1.2.1 Upstream Natural Gas Processing

During natural gas processing, SO_2 emissions may be released from sour gas (H_2S is removed and combusted), methane is also released during processing and distribution. AP-42 (U.S. EPA 1985, Section 5.3) provides emission factors for SO_2 emissions (26.98 $lb/10^6$ scf processed). A methane emission factor was developed from the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990:2001 (U.S. EPA 2003) for the year 2000 78.3 $Gg/10^9$ scf gas processed. Emission rates on a power output basis are provided in Table 7.1.

TABLE 7.1
UPSTREAM GAS PROCESSING AND DISTRIBUTION- EMISSION RATE (KG/MWH)

Constituent	Turbine Efficiency					
	70% cogen	60% combined	50% combined	40% single	30% single	20% single
SO_2	0.017	0.020	0.024	0.030	0.040	0.060
CH_4	0.110	0.128	0.154	0.192	0.256	0.384
CO_2[1]	3.3	3.9	4.7	5.8	7.8	11.7

1 Derived from (Dorland *et al.* 1997 – ExernE National Implementation – the Netherlands).

ExternE National Implementation – the Netherlands (Dorland *et al.* 1997) provides concise life-cycle emission rates. This document provided additional information to the emission factors derived from AP-42 (U.S. EPA 1985).

7.1.2.2 Construction of Natural Gas Facility

Construction of a natural gas facility will inherently require power to manufacture the construction materials and from transportation activities. Emissions from construction activities are presented in Table 7.2.

TABLE 7.2
NATURAL GAS PLANT CONSTRUCTION - EMISSION RATE (KG/MWH)
(DORLAND *et al* 1997)

	Constituent			
	SO_2	NO_x	Particles	CO_2
Emission	0.00001	0.00024	0.00002	0.0113

The emissions associated with construction are a very small fraction of the emissions from the rest of the natural gas cycle – particularly generation.

7.1.2.3 Stationary Gas Turbines

In addition to natural gas, gas turbines can also burn other fuels such as digester gas (perhaps from biomass) and landfill gas. Emission factors for these fuels are provided. One consideration with respect to landfill gas, is that if landfill gas were not used in a turbine, it would be released as methane. Methane has a higher global warming potential than the CO_2 that would be produced from its combustion. Consequently, the CO_2 arising from the portion of methane collected from landfills and conbusted, is not factored in this report since the landifll gas emissions (essentially methane) if not combusted, would constitute a higher GWP.

General assumptions and conversion factors used to estimate air emissions from processing and electrical production using gas turbines:

- natural gas has a heating value of 1020 Btu/scf (AP-42);
- landfill gas has a heating value of 400 Btu/scf (AP-42);
- digester gas has a heating value of 600 Btu/scf (AP-42);
- 3412 Btu/kWh;
- natural gas turbines have different possible configurations; single cycle, combined cycle and cogeneration. The primary difference between these configurations from an air quality perspective is the relative efficiency of the unit i.e. How much fuel is required to generate a kWh of power?
- Single cycle units are approximately 20-40% efficient;
- Combined cycle units are approximately 40-60% efficient;
- Cogeneration can have efficiencies greater that 60% and can be upwards of 80%.

TABLE 7.3
AP-42 EMISSION FACTORS – STATIONARY GAS TURBINES
(SECTION 3.1) (LB/MMBTU)

	NO_x	SO_2	PM_{10}	CO_2	CH_4	N_2O	Benzene	Formaldehyde
Nat Gas Uncontrolled	0.32	0.0034	0.0066	110	8.60E-03	3.00E-03		7.10E-04
Nat Gas Water-Steam Injection	0.13							
Nat Gas Dry-Low NOx	0.099							
Landfill gas	0.14	0.045	0.023	50			2.10E-05	
Digester gas	0.16	0.0065	0.012	27				1.90E-04

TABLE 7.4
GAS TURBINES - EMISSION RATE (kg/MWh)

	Turbine Efficiency					
	70% cogen	60% combined	50% combined	40% single	30% single	20% single
NO_x						
Nat Gas Water-Steam Injection	0.29	0.34	0.40	0.50	0.67	1.01
Nat Gas Dry-Low NO_x	0.22	0.26	0.31	0.38	0.51	0.77
Landfill gas	0.79	0.92	1.11	1.38	1.84	2.76
Digester gas	0.60	0.70	0.84	1.05	1.40	2.11
SO_2						
Nat Gas	0.005	0.008	0.009	0.011	0.013	0.018
Landfill gas	0.254	0.296	0.355	0.444	0.592	0.888
Digester gas	0.024	0.029	0.034	0.043	0.057	0.086
PM_{10}						
Nat Gas	0.010	0.015	0.017	0.020	0.026	0.034
Landfill gas	0.130	0.151	0.182	0.227	0.303	0.454
Digester gas	0.045	0.053	0.063	0.079	0.105	0.158

TABLE 7.5
GAS TURBINES - EMISSION RATE (kg/MWh)

	Turbine Efficiency					
	70%	60%	50%	40%	30%	20%
	cogen	combined	combined	Single	Single	single
HAP						
Formaldehyde - Natural Gas	0.00157	0.00001	0.00001	0.00001	0.00001	0.00001
Formaldehyde - Digester Gas	0.00042	0.00346	0.00404	0.00485	0.00606	0.00808
Benzene - Landfill Gas	0.00005	0.00005	0.00007	0.00008	0.00011	0.00016
GHG						
CO_2 nat gas	243	284	341	426	568	851
CO_2 digester gas	152	178	213	266	355	533
Methane	0.129	0.150	0.180	0.225	0.300	0.450
N_2O	0.007	0.008	0.009	0.012	0.015	0.023

TABLE 7.6
NORMALIZED CONTAMINANT EMISSIONS (kg/MWh)

Technology	70%	60%	50%	40%	30%	20%	Notes
	cogen	combined	combined	single	single	single	
Nat Gas Water-Steam Injection	0.6	0.7	0.8	1.0	1.3	2.0	Includes nat gas processing
Nat Gas Dry-Low NO_x	0.5	0.6	0.7	0.9	1.1	1.7	Includes nat gas processing
Landfill gas	0.9	1.0	1.2	1.5	2.0	3.0	No upstream processing
Digester gas	0.7	0.8	1.0	1.3	1.7	2.5	No upstream processing

TABLE 7.7
GhG EMISSIONS (TONNES CO_2-eq/MWh)

Fuel	70%	60%	50%	40%	30%	20%	Notes
	cogen	combined	combined	single	single	single	
Nat Gas	0.25	0.29	0.35	0.44	0.59	0.88	Includes nat gas processing
Landfill Gas	0	0	0	0	0	0	Methane from landfill would be coverted to CO_2 with a lower GWP.
Digester Gas	0.15	0.18	0.22	0.27	0.36	0.54	No upstream processing

7.1.2.4 Radioactivity Emissions Associated with Natural Gas Combustion

It should also be noted that natural gas processing can result in the release of radioactive radon gas. UNSCEAR 2000 has estimated, on a world –wide basis that radon-222, which is a naturally occurring radioactive gas, is released from both oil and gas extraction as indicated in the following table. UNSCEAR 1993 also reports a normalized collective dose for gas fired power plants as illustrated in Table 7.8.

TABLE 7.8
RADIOACTIVITY EMISSIONS FROM THE NATURAL GAS FUEL CYCLE

	Radon Release (TBq/y)[1]	Normalized Collective Dose (person Sv/GWa)[2]
Gas Extraction	0.5	
Gas Fired Power Plant	0.23	0.03

[1] UNSCEAR 2000
[2] UNSCEAR 1993

7.1.3 Coal Fuel Cycle

7.1.3.1 Coal Mining

Emissions from coal mining activities were obtained from the Environment Canada Criteria Air Contaminant (CACs) Emission Summary (Environment Canada 2005a). CACs emissions for 2000 are summarized by industry type. The Natural Resources Canada (NRCAN) web site (NRCan 2005a) also provides the quantity of coal mined in 2000 at 76 million short tons (69 million tonnes). From these values the emission rates in Table 7.9 were derived.

TABLE 7.9
2000 CRITERIA AIR CONTAMINANT EMISSIONS FOR CANADA

	NO_x	SO_x	PM_{10}
Coal Mining Industry Emissions (tonnes)	1,538	1,958	6,400
emissions (kg/tonne of coal mined)	0.02	0.03	0.09

Methane is also released from the coal matrix during mining. Environment Canada (2005b) web site Information on Greenhouse Gas Sources and Sinks provides methane emission rates for coal mining as presented in Table 7.10.

TABLE 7.10
METHANE EMISSION RATES FOR COAL MINING.

Mining Method	Coal Type	Methane Emission (t/kt coal)
Underground	Bituminous	6.55
Surface	Bituminous	0.32
	SubBituminous	0.19

The following assumptions were used to convert the emission rates to an electrical generation basis:

- The heat value of bituminous coal is approximately 12700 Btu/lb (AP-42 (U.S. EPA 1985) Section 1.1.);
- The heat value of subbituminous coal is approximately 9760 Btu/lb;

- The NRCan Web site, Canada's Energy Markets (NRCan 2005b) identifies that approximately 65% of Canada's coal reserve is bituminous coal and 35% subbituminous;
- The average heat value of coal is therefore 11,690 Btu/lb.

As for the natural gas fuel cycle, emissions from coal mining were developed power output basis. Emissions for coal transport, and are from ExternE National Implementation – the Netherlands (Dorland et al. 1997). The emission rates for coal mining and transport are presented in Table 7.11.

TABLE 7.11
ESTIMATED EMISSION RATES (kg/MWh)
FROM COAL MINING AND COAL TRANSPORT

Constituent	Coal Mining Emissions (kg/MWh)				Coal Transport Emissions (kg/MWh)
	35%	40%	50%	60%	
NO_x	0.008	0.007	0.006	0.005	
SO_2	0.011	0.009	0.008	0.006	
PM_{10}	0.035	0.031	0.025	0.021	
$PM_{2.5}$	0.016	0.014	0.011	0.009	
CO_2					79
CH_4	0.705	0.617	0.493	0.411	

7.1.3.2 Construction of Coal Fired Generating Station

ExternE National Implementation – the Netherlands (Dorland *et al.* 1997) reports estimated emission rates from power plant construction. Similarly to the natural gas cycle, emissions from construction of the power plant are only a small fraction (<1%) of the life-cycle emissions and are not included in this analysis.

7.1.3.3 Bituminous and Sub-bituminous Coal Combustion

Emission rates are from AP-42 (U.S. EPA 1985) Section 1.1 – Bituminous and Subbituminous Coal Combustion. The majority of Canada's coal reserves are bituminous and subbituminous coal, therefore emissions from other types of coal are not included in this assessment. Several assumptions have been made:

- Only technologies which comply with NSPS were considered
- Sulphur content - 1%
- Calcium to sulphur ratio – 3
- Efficiency of combustion unit – 35%

- Carbon content of bituminous coal - 75%; sub-bituminous coal – 40%
- Emissions controls considered:
  - Low-NO_x burner (NO_x emission reduction 45%)
  - Low-NO_x burner with post burner control (NO_x emission reduction 86%)
  - SO_2 control – scrubber to remove 90% of emissions
  - Particulate control – 99% control (ESP, fabric filter etc.)

The U.S. EPA Emission factors are provided in Table 7.12 for bituminous and sub-bituminous coal, for the different coal firing practices.

TABLE 7.12
AP-42 EMISSION FACTORS – BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION (SECTION 1.1) (lb/ton coal feed)

Firing Practice	Coal Type	Uncontrolled AP-42 emissions lb/ton coal feed								
		SO_2	NO_x	PM	Hg	Formaldehyde	Benzene	CO_2	CH_4	N_2O
Pulverized Coal	Bitminous	38	16.8	19.2	8.30E-05	2.46E-04	4.54E-05	5445	0.043	0.06
	Subbitminous	35	13.2					2904		
Cyclone	Bitminous	38	33	2.08				5445	0.01	0.09
	Subbitminous	35	17					2904		
Stoker	Bitminous	38	11	11.1				5445	0.06	0.04
	Subbitminous	35	8.8					2904		
Fluidized Bed – Circulating Bed		4.9	5	12.4				5445	0.06	3.5
Fluidized Bed – Bubbling		14.7	15.2					2904		

The emission rates from coalfired generation on a power output basis are provided below:

TABLE 7.13
CONVENTIONAL CONTAMINANT EMISSIONS FROM COAL FIRED GENERATING STATION

NO_x (kg/MWh)		Low NO_x Burner				Low NO_x Burner+Post Burner Control			
		35%	40%	50%	60%	35%	40%	50%	60%
Pulverized Coal		1.61	1.41	1.13	0.94	0.40	0.35	0.28	0.24
Cyclone		2.85	2.49	2.00	1.66	0.71	0.62	0.50	0.42
Stoker		1.06	0.93	0.75	0.62	0.27	0.23	0.19	0.16
Fluidized Bed	circulating	0.52	0.46	0.36	0.30	0.13	0.11	0.09	0.08
Fluidized Bed	bubbling	1.58	1.38	1.11	0.92	0.40	0.35	0.28	0.23

SO_2 (kg/MWh)		35%	40%	50%	60%
Pulverized Coal		0.70	0.61	0.49	0.41
Cyclone		0.70	0.61	0.49	0.41
Stoker		0.70	0.61	0.49	0.41
Fluidized Bed	circulating	0.09	0.08	0.07	0.05
Fluidized Bed	bubbling	0.28	0.24	0.20	0.16

HAPs (kg/MWh)	35%	40%	50%	60%
Mercury	1.57E-05	1.37E-05	1.10E-05	9.16E-06
Formaldehyde	2.46E-04	2.15E-04	1.72E-04	1.43E-04
Benzene	4.54E-05	3.97E-05	3.18E-05	2.65E-05

Particulate (kg/MWh)		PM_{10}				$PM_{2.5}$			
		35%	40%	50%	60%	35%	40%	50%	60%
Pulverized Coal		0.036	0.032	0.025	0.021	0.009	0.008	0.007	0.006
Cyclone		0.004	0.003	0.003	0.002	0.002	0.001	0.001	0.001
Stoker		0.021	0.018	0.015	0.012	0.007	0.006	0.005	0.004
Fluidized Bed	circulating	0.023	0.021	0.016	0.014	0.008	0.007	0.006	0.005
Fluidized Bed	bubbling	0.023	0.021	0.016	0.014	0.008	0.007	0.006	0.005

TABLE 7.14
GREENHOUSE GAS EMISSIONS FROM COAL FIRED GENERATING STATION

CO_2 (GWP - 1)		35%	40%	50%	60%
Pulverized Coal		862	754	603	503
Cyclone		862	754	603	503
Stoker		862	754	603	503
Fluidized Bed	circulating	862	754	603	503
Fluidized Bed	bubbling	862	754	603	503

CH_4 (GWP - 21)		35%	40%	50%	60%
Pulverized Coal		0.008	0.007	0.006	0.005
Cyclone		0.002	0.002	0.001	0.001
Stoker		0.011	0.010	0.008	0.007
Fluidized Bed	circulating	0.011	0.010	0.008	0.007
Fluidized Bed	bubbling	0.011	0.010	0.008	0.007

N_2O (GWP - 270)		35%	40%	50%	60%
Pulverized Coal		0.011	0.010	0.008	0.007
Cyclone		0.017	0.015	0.012	0.010
Stoker		0.008	0.007	0.005	0.004
Fluidized Bed	0.662	0.579	0.464	0.386	503
Fluidized Bed	0.662	0.579	0.464	0.386	503

The normalized emission factors for the coal fuel cycle are presented in the following tables:

TABLE 7.15
NORMALIZED CONTAMINANT EMISSIONS FROM THE COAL FUEL CYCLE
(kg/MWh)

		Low NO_x Burner				Low NO_x Burner+Post Burner Control			
		35%	40%	50%	60%	35%	40%	50%	60%
Pulverized Coal		3.3	2.9	2.3	1.9	2.1	1.8	1.4	1.2
Cyclone		4.4	3.8	3.1	2.6	2.2	2.0	1.6	1.3
Stoker		2.7	2.3	1.9	1.6	1.9	1.6	1.3	1.1
Fluidized Bed	circulating	1.0	0.9	0.7	0.6	0.6	0.6	0.4	0.4
Fluidized Bed	bubbling	2.4	2.1	1.7	1.4	1.2	1.1	0.9	0.7

TABLE 7.16
GLOBAL WARMING POTENTIAL FROM THE COAL FUEL CYCLE
(Tonnes CO_2 eq/MWh)

		GWP (Tonnes CO_2-eq /MWh)			
		35%	40%	50%	60%
Pulverized Coal		0.96	0.85	0.70	0.59
Cyclone		0.96	0.85	0.70	0.59
Stoker		0.96	0.85	0.69	0.59
Fluidized Bed	circulating	1.14	1.00	0.82	0.70
Fluidized Bed	bubbling	1.14	1.00	0.82	0.70

7.1.3.4 Coal Gasification

Coal can be converted to organic gases and liquids, to use conventional gas firing practices. Goal gasification involves combining coal with oxygen and steam to produce a combustible gas. In theory, the coal could be gasified, which can produce a product suitable for use in gas turbines. There is currently little commercial coal conversion. Consequently there is little information available on the emissions associated with the gasification process. Emissions from the gasification process may include ash dust, organic, and inorganic gases and CO_2.

There have been two successful Integrated Gasification Combined Cycle (IGCC) demonstration projects in the United States. These process involve extensive controls to capture the emissions and burn them in an integrated combined cycle turbine.

Reported emissions from the IGCC at Wabash River are provided in Topical Report Number 20 "*Clean Coal Technology – The Wabash River Coal Gasification Repowering Project*" (U.S. Department of Energy (DOE) and Wabush River Coal Gasification Project Joint Venture, 2000).

TABLE 7.17
REPORTED EMISSIONS (kg/MWh) FROM THE WABASH RIVER IGCC

SO_2	NO_x	PM_{10}	Normalized
0.61	0.49	0.00	1.61

Corti A. and L. Lombardi (2003) reports life cycle CO_2 emissions for IGCC generation facilities. As illustrated in the following tables, emissions from IGCC construction are only a small fraction of the total, therefore emissions from other contaminants are not reported for construction.

TABLE 7.18
IGCC LIFE-CYCLE GHG EMISSIONS
(Tonnes CO_2-eq/MWh)

GHG Emissions	Tonnes CO_2-eq/MWh
Coal Production and Transportation	0.22
IGCC Construction	0.001
IGCC Maintenance	0.003
Energy Conversion	
Without CO2 removal	0.75
Chemical Absorption (83% removal)	0.13
CO2 removal (90% removal)	0.07

New technologies are being developed for CO_2 removal such as chemical or physical absorption and/or pressure induced CO_2 recovery. Speculative technologies include CO_2 capture for use with a solid oxide fuel cell. The following tables presents CO_2 emissions rates for likely technologies (Gielen, 2003).

TABLE 7.19
IGCC LIFE-CYCLE GLOBAL WARMING POTENTIAL
FOR DIFFERENT SEQUESTRATION SCENARIOS

GWP (Tonnes CO_2-eq /MWh)	Tonnes CO_2-eq/MWh
Without CO_2 removal	0.98
Chemical Absorption (83% removal)	0.36
CO_2 removal (90% removal)	0.30

7.1.3.5 Radioactivity Emissions from the Coal Fuel Cycle

The major component of coal is carbon. However, depending on the source of the coal, coal contains varying amounts of inorganic matter including trace elements and radionuclides. During mining operations, radon is released along with the methane that is trapped in the coal matrix. UNSCEAR 1993 reports radon emissions from coal mines (30-800 TBq/y) and estimates a collective effective dose of 0.5-10 person Sv/y. UNSCEAR 1993, uses these values to estimate a normalized collective effective dose of 20 person Sv/GW a.

During coal combustion, most of these elements are released and distributed between the gas phase and solid combustion products depending on the volatility of each element. Most of the radon gas is lost in stack emissions because it is transferred to the gas phase. Less volatile elements which again include Uranium and Thorium with their decay also result in air emissions of radioactivity. Some of the radioactivity will also distribute to the bottom ash.

A study by the U.K. National Radiological Protection Board (NRPB), Smith et al (2001) predicted peak individual doses from atmospheric releases from the stack of a coal-fired power station of about 1.5 μSv/y. While this is a small dose, they may not be insignificant when compared to the radiological impact of nuclear power stations. As noted by Gabbard (1993), the United States National Council on Radiation Protection and Measurements (NCRP) estimates that population exposures from operation of 1000 MWe nuclear and coal-fired power plants in the U.S. amounts to 4.9 person-Sv/y for coal plants and 0.048 person-Sv/y for nuclear plants (U.S. NCRP 1987a, 1987b). Thus,at least in the US, the population dose from coal plants is about 100 times that from nuclear plants.

TABLE 7.20
RADIOACTIVITY EMISSIONS AND COLLECTIVE DOSES FOR COAL MINING AND COAL FIRED POWER PLANT

	Radon Release (TBq/y)	Collective Effective Dose (person Sv/y)	Normalized Collective Effective Dose (person Sv/GW a)
Coal Mining	30-800[1]	0.5-10[1]	20[1]
Coal Fired Power Plant	0.034[2]	4.9[3]	0.5[1]

[1] UNSCEAR 1993

[2] UNSCEAR 2000

[3] Gabbard 1993 (U.S. alone, collective dose varies greatly by country; for example UNSCEAR 1993 estimates a normalized collective effective dose of 20 person Sv/GW a for China as a result of older technology and higher radionuclide levels in air)

7.1.4 Biomass

Biomass is a potential fuel source, however, it is both land and labour intensive to produce. It is unlikely to be economically viable; however climate policy initiatives may make this a fuel source worth considering in the future. Two alternative of using biomass considered by ExternE National Implementation – the Netherlands (Dorland et al. 1997) are:

- the incorporation of biomass into the fuel cycle at a coal fired generating stations; or,
- gasifying the biomass to fuel a combined cycle (CC) gas plant.

The results of the life-cycle evaluation considered by Dorland (1997) are presented below:

TABLE 7.21
LIFE-CYCLE EMISSION RATES FOR CONVENTIONAL POLLUTANTS - BIOMASS COMBUSTION IN A COAL PLANT

	SO_2 (kg/MWh)	NO_x (kg/MWh)	PM_{10} (kg/MWh)	$PM_{2.5}$ (kg/MWh)
Biomass Production				
Seedlings/Fertiliser/Protection	0.007	0.015	0.00035	0.00018
Machines/Chipping	0.017	0.105	0.00170	0.00085
Biomass Transport	0.005	0.043	0.00029	0.00022
Limestone Extraction and Transport	0.0019	0.007	0.00007	0.00005
Power Plant Construction	1.08E-06	0.0000066	1.10E-07	8.25E-08
Power Generation	0.01	0.17	0.004	0.00293
Power Plant dismantling	1.08E-06	0.0000066	1.10E-07	8.25E-08
Waste Transport	0.00042	0.0034	0.000023	0.000017
Total Emissions	**0.041**	**0.343**	**0.006**	**0.004**

TABLE 7.22
LIFE-CYCLE EMISSION RATES FOR CONVENTIONAL POLLUTANTS - BIOMASS GASIFICATION COMBUSTION IN A CC GAS PLANT

	SO_2 (kg/MWh)	NO_x (kg/MWh)	PM_{10} (kg/MWh)	$PM_{2.5}$ (kg/MWh)
Biomass Production				
Seedlings/Fertiliser/Protection	0.006	0.014	0.00034	0.00017
Machines/Chipping	0.017	0.102	0.00170	0.00085
Biomass Transport	0.004	0.027	0.00044	0.00033
Limestone Extraction and Transport	0.0021	0.013	0.00021	0.00016
Power Plant Construction	1.90E-05	0.00012	1.90E-06	1.43E-06
Power Generation	0.074	0.22	0.030	0.02250
Power Plant dismantling	1.90E-05	0.00012	1.90E-06	1.43E-06
Waste Transport	0.0008	0.0064	0.000042	0.000032
Total Emissions	**0.105**	**0.386**	**0.033**	**0.024**

TABLE 7.23
NORMALIZED CONVENTIONAL EMISSION RATES – BIOMASS LIFE CYCLE

	kg/MWh				
	SO_2	**NO_x**	**PM_{10}**	**$PM_{2.5}$**	**Normalized**
WCF (Coal Plant - Biomass Portion)	0.041	0.343	0.006	0.004	0.5
WG-Plant (Gasification Plant)	0.105	0.386	0.033	0.024	0.8

TABLE 7.24
LIFE CYCLE CO_2 EMISSIONS RATES – BIOMASS

	Coal Plant (Tonnes/MWh)	**Gassification and CC-Plant (Tonnes/MWh)**
Biomass Production		
Biomass growth	-1.04	-1.04
Seedlings/Fertiliser/Protection	0.008	0.008
Machines/Chipping	0.016	0.015
Biomass Transport	0.003	0.040
Limestone Extraction and Transport	0.001	0.002
Power Plant Construction	1.077	1.035
Power Generation	0.00000	0.00002
Power Plant dismantling	0.00000	0.00002
Waste Transport	0.00030	0.00044
Total Emissions	**1.10**	**1.10**
Total Emissions Considering Biomass Growth	**0.07**	**0.06**

TABLE 7.25
BIOMASS LIFE-CYCLE GLOBAL WARMING POTENTIAL

GWP (Tonnes CO2-eq /MWh)	**WCF (Coal Plant - Biomass Portion)**	**WG-Plant (Gasification Plant)**
CO_2 Total	1.10	1.10
CO_2 Considering Biomass Growth	0.07	0.06

7.1.5 Hydroelectric Power

There are no atmospheric emissions from the hydroelectric generation itself; however, flooding practices can result in methane emissions due to decomposition of vegetation within the flooded reservoir. Hydro Quebec (*Environmental Performance and Social Role – 2001*) estimates 15 kt CO_2 eq/TWh (0.015 tonne CO_2 eq/MWh) from flooded reservoirs and 2 kg CO_2 eq/TWh (0.002 tonne CO_2 eq/MWh) from run-of-river hydroelectric.

Activities associated with the construction of the dam also result in emissions, primarily CO_2 due to manufacture of the concrete used in the dam. The International Energy Agency (2002) reports CO_2 emissions associated with the construction of two different hydroelectic dams, once constructed with rock and concrete, and the other constructed with only concrete.

Koch (2001) presents an summary of relative life-cycle emissions released for different generation options based on information presented in IEA 2002. These relative values were used to estimate emissions of the other conventional pollutants.

TABLE 7.26
EMISSIONS PRODUCED BY 1 KW OF ELECTRICITY BASED ON LIFE CYCLE ANALYSIS (KOCH 2001)

Generation option	Greenhouse gas emissions gm equiv CO_2/kWh	SO_2 emissions milligram /kWh	NO_x emissions milligram /kWh	NMVOC milligram /kWh	Particulate matter milligram /kWh
Hydropower	2-48	5-60	3-42	0	5
Coal – modern plant	790-1 182	700-32 321+	700–5 273+	18-29	30-663+
Nuclear	2–59	3-50	2-100	0	2
Natural Gas (combined cycle)	389–511	4-15 000+[4]	13+-1500	72-164	1-10+
Biomass forestry waste combustion	15–101	12-140	701-1950	0	217-320
Wind	7–124	21-87	14-50	0	5-35
Solar photovoltaic	13–731	24-490	16-340	70	12-190

The estimated life-cycle emissions for hydroelectric power are presented in the following tables.

TABLE 7.27
CONVENTIONAL POLLUTANT EMISSIONS FROM HYDROELECTRIC DAM CONSTRUCTION

Dam Construction	kg/MWh
SO_2	0.04
NO_x	0.03
PM_{10}	0.003
$PM_{2.5}$	0.003
Normalized	0.07

TABLE 7.28
GHG EMISSIONS FROM HYDROELECTRIC DAM CONSTRUCTION

Total CO_2-Eq Emissions	T CO_2-eq/MWh
Dam Construction	
Rock Filled Dam	0.00063
Concrete Dam	0.01740
Operation and Maintenance	
Rock Filled Dam	0.00007
Concrete Dam	0.00026
Degradation due to Flooding	
Run of River	0.002
Reservoir	0.015

TABLE 7.29
HYDROELECTRIC LIFE-CYCLE GLOBAL WARMING POTENTIAL

Total CO_2 Eq Emissions	T CO_2-eq/MWh
Rock Filled Dam - Run of River	0.003
Concrete Dam - Run of River	0.020
Rock Filled Dam - Reservoir	0.016
Concrete Dam - Reservoir	0.033

7.1.6 Nuclear Power Generation

Various nuclear technologies are to be considered: CANDU 6 – New; CANDU 6 – Refurbished; Advanced CANDU Reactor (ACR); Pressurized Water Reactor (PWR); Boiling Water Reactor (BWR). Most of these are well established technologies such as CANDU 6 while others such as advanced CANDU are still in the development stage. New nuclear generation is of worldwide interest and a number of technologies not currently included for consideration may well become viable options in the not too distant future.

In evaluating nuclear technologies, it is important to understand that all of the western countries with commercial nuclear power are subject to meeting or bettering an annual dose of 1 mSv/a (1000 μSv/a) to the most exposed individual. In practice, the actual doses from nuclear

generation are very much lower. For example, in 2004, the doses to the most exposed person living next to the Pickering and Darlington nuclear generating stations were 4.1 μSv (0.0041 mSv) and 1.2 μSv (0.0012 mSv) respectively. UNSCEAR 2000 reports estimates of annual dose to individuals for various reactor types and provides (nominal) values of 10 μSv/a for BWRs and HWRs and 2 μSv/a for LWRs. As noted previously, doses decrease with increasing distance from a nuclear facility. For context, UNSCEAR 2000 estimates a world-wide per caput dose from natural background sources of radiation and radioactivity of about 2.4 mSv per year (2,400 μSv per year) which can be compared to their estimates of maximum annual per caput dose of about 0.2 μSv/y from nuclear power production fuel cycle activities as a whole.

In view of the very high level of scrutiny given to nuclear generation, it is considered that since current doses to neaby people are typically in the order of 10 uSv/a or less, that future doses from nuclear generation to the most exposed nearby resident arising from operation of any of the alternative nuclear reactors, is unlikely to be more than about 10 μSv/a. Thus, the maximum individual dose is not informative with respect to alternative nuclear generation technologies. Therefore, the UNSCEAR concept of collective dose has been acapted for present purposes.

7.1.6.1 Conventional Pollutant Emissions from the Nuclear Fuel Cycle

Conventional emissions from the nuclear cycle life cycle have been presented by the International Energy Agency (IEA 2002) in a report "*Environmental and Health Impacts of Electricity Generation – A Comparison of the Environmental Impacts of Hydropower with those of Other Generation Technologies"*. This was a 5 year study involving 112 experts from 16 countries, the World Bank and the World Commission of Dams. IEA (2002) presents the life cycle emissions for conventional parameters related to manufacturing materials for construction, construction activities, and facility operation for three reactor types; boiling water reactor (BWR), advanced BWR and breeder reactor. The conventional emissions associated with the BWR were assumed to apply to the different reactors considered in this study. The emissions from mining were derived from coal mining emissions, but adjusted for the quantity of fuel required per MWh (380 tonnes coal/MWh; 0.029 tonnes uranium/MWh – UNSCEAR 2000).

TABLE 7.30
CONVENTIONAL POLLUTANTS EMISSIONS FROM NUCLEAR FUEL CYCLE
(IEA (2002)

Mining	NO_x (kg/MWh)	SO_2 (kg/MWh)	PM_{10} (kg/MWh)	$PM_{2.5}$ (kg/MWh)
	6.38E-07	8.12E-07	2.65E-06	1.18E-06

Manufacturing and Construction of Power Plant	**CO_2 kg/MWh**	**SO_2 kg/MWh**	**NO_x kg/MWh**	**Particles kg/MWh**
Average BWR	2.03	0.0023	0.0426	0.0029
Advanced BWR	3.93	0.0044	0.0826	0.0056

Operation and Maintenance	**CO_2 kg/MWh**	**SO_2 kg/MWh**	**NO_x kg/MWh**	**Particles kg/MWh**
Average BWR	9.89	0.011	0.208	0.014
Advanced BWR	4.93	0.006	0.104	0.007

Dismantling	**CO_2 kg/MWh**	**SO_2 kg/MWh**	**NO_x kg/MWh**	**Particles kg/MWh**
Average BWR	0.123	0.123	0.0001	0.0026
Advanced BWR	0.07	0.070	0.0001	0.0015

Emission Summary	**NO_x kg/MWh**	**SO_2 kg/MWh**	**PM_{10} kg/MWh**	**$PM_{2.5}$ kg/MWh**	**Normalized kg/MWh**
Average BWR	0.253	0.013	0.017	0.013	0.4
Advanced BWR	0.188	0.010	0.013	0.009	0.3

GHG Global Warming Potential	**Tonnes CO_2eq/MWh**
Average BWR	0.012
Advanced BWR	0.009
BWR and PWR light water reactor (Dones et. al 2005)	0.005-0.012

Dones *et. al.* (2005) have studies the life cycle inventories of nuclear (and natural gas) energy options in Europe. Amongst other information, these authors report the range of total GHG emissions for European light water reactors (including both BWRs and PWRs) of between 0.005 to 0.012 tonnes CO_2 eq/MWh, a range of values very comparable to those reported in IEA (2002).

7.1.6.2 Radioactivity Emissions from the Nuclear Fuel Cycle

Radioactivity emission rates and for and collective effective doses for the different reactor types were obtained from UNSCEAR (2000). The emission rates and collective doses presented are directly applicable to the reactors under consideration in this study. The CANDU reactor is a Heavy Water Reactors (HWR). For the conceptual ACR, emissions are not readily available, but for present purposes are assumed to be the same as the CANDU (HWR).

TABLE 7.31
NORMALIZED RELEASES AND COLLECTIVE EFFECTIVE DOSE FOR UPSTREAM ACTIVITIES FOR THE NUCLEAR Cycle (TBq/GWa) (1995-1997) (UNSCEAR 2000)

Upstream of Reactor	Normalized Radon Release (TBq/GWa)	Normalized Collective Effective Dose (person Sv/GWa)
Mining	75	0.19
Milling	3	0.0075
Operational Mill Tailings (assumed 5 y release)	3	0.04
Conversion, Enrichment and Fuel Fabrication		0.003

TABLE 7.32
NORMALIZED RELEASES FOR DIFFERENT REACTORS (TBq/GWa) (1995-1997) (UNSCEAR 2000)

Reactor Emissions	Noble Gases	Tritium	Carbon-14	Iodine-131	Particulate	Tritium liquid	Other liquid
Pressurized Water Reactor (PWR)	13	2.4	0.22	0.0002	0.0001	19	0.008
Boiling Water Reactor (BWR)	180	0.86	0.51	0.0003	0.35	0.87	0.011
Heavy Water Reactor (HWR)	250	330	1.6	0.0001	0.00005	340	0.044

In addition to doses in current years, UNSCEAR has considered potential future does for long-lived radionuclides. In performing their analysis, UNSCEAR considered the collective dose from radon from mill tailings out to 10,000 year in the future. It should also be noted that with respect to dose from mill tailings, UNSCEAR's analysis utilizes a simple generic dilution factor and that use of a more detailed dispersion factor leads to an estimate of about 1.4 person Sv/GW a (UNSCEAR 2000 paragraph 122). Consequently, the estimate of 7.5 person Sv/GW a may be somewhat conservative.

TABLE 7.33 COLLECTIVE DOSE PER UNIT OF ELECTRICAL ENERGY GENERATED (person Sv/GW a) (1990-1994) (UNSCEAR 2000)

Reactor Doses	Noble Gases	Tritium	Carbon-14	Iodine-131	Particulate	Tritium liquid	Other liquid
Pressurized Water Reactor (PWR)	0.003	0.005	0.059	0.0001	0.0004	0.014	0.006
Boiling Water Reactor (BWR)	0.15	0.002	0.14	0.0002	0.36	0.0006	0.014
Heavy Water Reactor (HWR)	0.23	1.4	0.43	0.0001	0.0001	0.32	0.043

TABLE 7.34
RADON RELEASES AND NORMALIZED COLLECTIVE EFFECTIVE DOSE – SOLID WASTE DISPOSAL (UNSCEAR 2000)

	Normalized Radon Release (TBq/GWa)	Normalized Collective Effective Dose (person Sv/GW a)
Mill Tailings - Closed Mill (assumed 10,000 year release)	0.3	7.5
Reactor Operation - Low Level Radioactive Waste		0.00005
Reactor Operation - Intermediate Level Radioactive Waste		0.5
Reprocessing Solid Waste Disposal		0.05
Globally dispersed radionuclides (truncated to 10,000 years)		40

TABLE 7.35
SUMMARY OF LIFE-CYCLE NORMALIZED COLLECTIVE DOSES FOR THE NUCLEAR CYCLE

Life-Cycle Normalized Collective Dose	Collective Dose per unit of electrical Energy Generated (person Sv/GW a)			
	Upstream	Reactor	Solid Waste	Total
Pressurized Water Reactor (PWR)	0.2	0.09	8.1	8.4
Boiling Water Reactor (BWR)	0.2	0.67	8.1	9.0
Heavy Water Reactor (HWR)	0.2	2.42	8.1	10.7

7.1.7 Wind Turbines

While there are no emissions associated with the operation of wind turbines, there are emissions from manufacturing materials for construction, and construction activities themselves. Life cycle emissions for wind turbines presented below, were developed from emissions reported in "*ExternE National Implementation – the Netherlands"* (Dorland 1997) and "*ExternE National Implementation – the Denmark"* (Schleisner and Nielsen 1997).

TABLE 7.36
LIFE CYCLE CONVENTIONAL CONTAMINANT EMISSIONS FROM WIND TURBINES

	SO_2 (kg/MWh)	NOx (kg/MWh)	PM_{10} (kg/MWh)	$PM_{2.5}$ (kg/MWh)	Normalized (kg/MWh)
Construction	0.060	0.042	0.029	0.02	0.15

TABLE 7.37
LIFE-CYCLE GLOBAL WARMING POTENTIAL FROM WIND TURBINES

	Tonnes CO_2-eq/MWh
Construction	0.012

7.1.8 Photovoltaics

Similar to wind turbines, there are not emissions associated with the operation of photovoltaic systems. Emissions are associated with manufacturing materials for construction, and construction activities. Life-cycle CO_2 emissions for photovoltaic systems were presented by Frankl (2001) at the Externalities and Energy Policy: Nuclear Energy Agency Workshop Proceedings 15-16 November 2001. These emissions were used to develop conventional pollutant emissions along with the relative life-cycle emissions released for different generation options presented in Section 7.1.5.

TABLE 7.38
LIFE CYCLE CONVENTIONAL CONTAMINANT EMISSIONS FROM PHOTOVOLTAICS

	SO_2 (kg/MWh)	NO_x (kg/MWh)	PM_{10} (kg/MWh)	$PM_{2.5}$ (kg/MWh)	Normalized (kg/MWh)
Construction	0.36	0.25	0.14	0.10	1.9

TABLE 7.39
LIFE-CYCLE GLOBAL WARMING POTENTIAL FROM PHOTOVOLTAICS

		Tonnes CO_2-eq/MWh
Construction	Ton/MWh	0.531

7.2 LAND IMPACTS

The impacts of power generation on land can occur during the lifecycle of the project, including extraction, processing of raw materials, transportation, construction, and operation and decommissioning. Many of the impacts are site-specific and therefore, difficult to generalize and beyond the focus of this exercise. Such impacts include the construction of access roads which are excluded from land impacts as presented here because the need for access roads will be site specific.

In terms of the broad category of land use impacts, the loss of habitat or land that will be permanently altered, the quality of land impacted/lost and the permanence of the loss are broad indicators of impact. For this evaluation, the loss of land will be quantitatively evaluated while the quality of the original land and the permanence of the loss will be evaluated more qualitatively as modifiers.

7.2.1 Land Use

This criterion is intended to provide a measurement of the amount of land used by a particular generation option per megawatt (land-use/megawatt). The land use calculation reflects the facility footprint or the acres required for the facility and associated components i.e. inside the fence. However, this estimation specifically does not include facility access roads because they were considered a site-specific variable.

In order to estimate land use for each generation options, footprint values per megawatt were calculated for existing or proposed generating stations.

7.2.1.1 Thermal

Natural Gas

Estimates of land use for natural gas fired stations were obtained for the proposed Sithe Energies Canadian Development Ltd. natural gas fuelled combined cycle Goreway Station (Sithe Energies, 2000), the proposed natural gas fired combined cycle cogeneration facility Portlands Energy Centre (Portlands Energy Centre, 2003) and the proposed Brighton Beach Power Station (ATCO, 2001). Values for land use at natural gas generating stations are presented in Table 7.1.

Coal and Synthetic Gas

An estimate for both advanced coal and synthetic gas land use was made from the proposed Mesaba Energy Project, a coal integrated gasification combined cycle facility (Excelsior Energy, 2005a and 2005b). This proposed facility represents an advanced coal fired station that will produce synthetic gas for energy production, and is therefore viewed as a good estimate of what a new coal-fired station would entail with respect to land use. It is noted that the plant includes a "buffer zone" between the station and nearby communities.

Values for land use at coal and coal/synthetic gas stations are presented in Table 7.40.

Biomass

Estimates for land use for biomass generating station were found for a proposed energy plant project in Saint John, New Brunswick (Goucher, 2005 and CEAA, 2005) and for the proposed NGPP Minnesota Biomass plant in Waseca County Minnesota (EQB, 2003). Values for biomass generating station land use are presented in Table 7.40.

7.2.1.2 Nuclear

Approximate land use estimates were made from facility maps for three nuclear generating stations in Ontario; Darlington Nuclear Generating Station (OPG, 2002), Pickering Nuclear Generating Station (OPG, 2003b) and Bruce Nuclear Generating Station (OPG, 2005). Values for land use by nuclear generating stations are presented in Table 7.40.

7.2.1.3 Hydroelectric

For the three styles of hydroelectric generation, impoundment will result in the largest impacts to land use. Diversion stations should result in little or no impacts, except potentially from access road construction – which is site specific, and therefore not included in this analysis. A pumped

storage facility may result in the creation of none, one or more reservoirs. However the exact details of land impacts caused by pumped storage hydroelectric generation is site specific and can not be generalized. Although a search was made for land use impacts of existing large pumped storage generating stations in other countries, none were found. As such, it is assumed for the purposes of this document that both diversion and pumped storage hydroelectric generation options will be counted as none, unless more site specific information is made available.

Land use estimates for impounded hydroelectric generating stations were based primarily on the size of the reservoir created for the station. Estimates were found for the proposed Romaine Hydroelectric Complex (CEAA, 2005b) in Quebec, the proposed Péribonka Hydroelectric Facility (CEAA, 2004) in Quebec and the existing Mountain Chute Generating Station (MRWMR, 2004) in Ontario.

Land use estimates for hydroelectric generation are presented in Table 7.40.

7.2.1.4 Renewable

Wind Power

Land use impacts for renewable generation were estimated for wind generation based on the proposed Wolfe Island Wind Power Development project (CEAA, 2005c) and the proposed Melancthon Grey Wind Project (Canadian Hydro, 2005). Land use estimates for wind generation are presented in Table 7.40.

Pohtovoltaics

There are three types of PV installations: (1) Roof Integration; (2) Building Facade Integration; and (3) Open Field Location, otherwise known as Array Field power plants. Estimating land use for either roof or building façade integration does not capture the intent of the land use evaluation criteria because land has not been altered to create the generation option. As such, only for open field applications of PVs was the land use criterion calculated.

Actual data on land requirements is not readily available since there are few array field power plants presently in operation as most PV applications are roof integrations. One study (NEA, 2001) identified a PV field array in Italy that was generating 3 MW in about one acre of land. Energy production is, however, going to depend upon the amount and intensity of sunlight available, which is going to be greater in Italy than Ontario.

Fuel Cells

Data was not readily available to estimate the land requirements for fuel cell applications. It is suspected that for a large amount of fuel cell generation they would be similar to a thermal generating station however, confirmation of this could not be made.

7.2.1.5 OMI Project

Land use estimates for the OMI Project must include both those for the transmission line interconnection between Manitoba and Ontario and also the land use estimate for the generation station itself. However, because the exact land use estimate for the hydroelectric generation station that will supply power for the OMI Project is not known, the estimated impacts are based on the range of values found for impounded hydroelectric generation stations. The values for land use for the transmission and generation are then summed to provide an overall estimate for land use values. The land use values for the OMI Project are presented in Table 7.1.

TABLE 7.40
LAND USE FOR GENERATION OPTIONS DURING THE OPERATION PHASE

Generation Option	Generation Type	Proposed or Existing Station	Total land	Total Generation (MW)	Land Use Estimate (km^2/MW)
Thermal	Natural Gas	Goreway	20ha	800	0.00025
	Natural Gas	Portlands	11.3ha	550	0.00021
	Natural Gas	Brighton Beach	10ha	580	0.00017
	Coal/ Synthetic Gas IGCC	Mesaba	1000acres	600	0.0067
	Biomass	St. John	17acres	15.5	0.0044
	Biomass	NGPP Minnesota	52.9ha	38.5	0.014
Nuclear	CANDU	Pickering	2.1km^2	4,120	0.00051
	CANDU	Darlington	5.0km^2	3,524	0.0014
	CANDU	Bruce	13.4km^2	4,640	0.0029
Hydro	Impounded	Romaine	275km^2	1500	0.18
	Impounded	Péribonka	31.6km^2	385	0.082
	Impounded	Mountain Chute	32.4km^2	170	0.19
	Pumped Storage		0	0	0
	Diversion		0	0	0
Renewable	Wind	Wolfe Island	2510ha	120-240	0.10-.21
	Wind	Melancthon Grey	2500acres	67.5	0.15
	Photovoltaic		1acre	3	0.0013
OMI Project	Transmission Line		150km^2	1000	0.15
	Hydro Generation		Est.	1000	0.08-0.19
	OMI Project Total			1000	0.23-0.34

7.2.2 Land Use Modifiers

There are two modifying factors for land use:

1. Quality of Land Impacted/Lost - this modifier refers to the land use prior to development of new generation options. A multiplier representing the quality of the land that is displaced for the generation technology was assigned and will be incorporated into the final criteria ranking in Chapter 8 of this report.

The development of a brownfield site will actually represent a positive impact to the environment because it is likely to require clean-up before development. Therefore, the impact is less than other sites and the multiplier is less than one, in this case 0.75. In order to set a base, it was decided that an urban, suburban or industrial infill site[5] that has no contamination nor is currently developed is the base for land use and therefore receives a multiplier of one. The remaining classifications are intended to represent environments that are important economically, culturally or for natural resource value. These land classifications therefore all receive multipliers greater than one because they are more socially valuable. In setting the actual values for the land use quality multiplier, it was decided that quality of the land should not count for a positive or negative determinant more than 25% for this analysis. This is partially based on the somewhat site-specific nature of land quality and because there is a large degree of humn perception with respect to quality. For example, for a given piece of undeveloped forest, an isolated lot may have more perceived 'quality' than one that is immediately adjacent to a city or town and perhaps modifiers of 1.5 and 1.1 respectively would be more appropriate. Likewise, poor agricultural land that is nutrient deficient may be perceived at a lower 'quality' than a thriving vineyard in the Niagara Region where perhaps modifiers of 1 and 1.75 would be more appropriate. However, this kind of judgement was well beyond the scope of this document and a generalization had to be made. Table 7.41 Presents the modifiers and respective multipliers for the quality of land impacted.

TABLE 7.41
MODIFIERS AND RESPECTIVE MULTIPLIERS FOR LAND USE QUALITY

Modifier	Multiplier
Forest/Wilderness Undeveloped	1.25
Traditional Aboriginal Land Use	1.25
Agricultural	1.25
Infill Site	1
Brownfield Site	0.75

[5] An infill site is defined as a parcel of land that, while not a brownfield, is not undeveloped, natural habitat land. These sites may, or may not, have been previously developed but, are generally found with municipality limits.

However, after having developed this modifier, it is difficult to apply broadly. For any generation option, it is not possible to say that only one land classification is applicable. For example, it is impossible to say that a wind farm will only ever be developed on agricultural land and not on a brownfield site. As such, while this modifier may be important at a site specific level, it can not be applied broadly. Therefore, no multiplier for land quality was added to the land use values before ranking.

2. Permanence of Land Impacted - Some of the generation technologies can coexist with other land use activities. For example, although a relatively large area is required for a wind farm, land between the turbines can still be utilized for animal grazing or crop production. Reservoirs created by hydroelectric stations can provide passive recreational uses such as boating and fishing. Because these uses essentially make more land available than what is indicated by the value, the multiplier becomes one if no other land use is possible and less than one if the land still holds external value. If land can be used for other activities, the multipliers presented in Table 7.42 will be utilized.

This modifier essentially estimates the amount of land that would still be available for some form of use – either human or biological. In developing the numeric value for the multiplier, it was important that the range represent a logical estimate of what would be available. As such, questions such as "When a wind farm is developed, how much of the land is still available, and with sufficient quality, for human or biological use?" Similarly for hydroelectric reservoirs and 'buffer zones' around thermal or nuclear generating stations. Obviously the answer to these questions varies not only on a site specific basis but also by generation option. However, it was decided that broad generalizations regarding the amount of land that could have secondary usage either by humans (for recreation) or biological organisms (as habitat or even feeding sites) could be made. Caution was warranted not to over-estimate the amount of land that would be available because these sites, while available for use, may not represent the best quality. As such, it was decided that a 15% benefit could be applied to a site if it was available for human or biological use and that these 'benefits' would be additive if the site was available for both human and biological use.

TABLE 7.42
MODIFIERS AND RESPECTIVE MULTIPLIERS FOR LAND USE PERMANENCE OF IMPACT

Modifier	Multiplier
No other potential use	1
Potential for human use	0.85
Potential for biological use	0.85
Potential for both human and biological use	0.7

7.3 WATER IMPACTS

With respect to the aquatic environment, impacts from generation options, there are two general impacts; impacts resulting from use and consumption associated with the withdrawal of water, and impacts that result from changes to the instream availability of water such as through changes in water elevation or flow rate.

7.3.1 Water Use

Water use, as an important environmental criterion, is intended to capture the use – both consumptive and non-consumptive – of water by a generation option. Because a large portion of the water may be returned to the water body from which it is drawn, it is important to distinguish between the amount that is withdrawn and the amount that is not returned (consumed). Both numbers are presented at litres per megawatt hour of power generated.

Presented in Table 7.43 is general information collected regarding the withdrawal and consumptive rates of water use of different generation types. In all cases where a range was provided, the highest value was used for comparison purposes in order to present the worst case scenario.

7.3.1.1 Thermal and Nuclear

Water use by a thermal or nuclear generating station is dependant on a number of factors. Of primary importance for generating stations where use is for cooling purposes, is the style of cooling water system. All cooling water systems draw water from the ambient water body and then either consume the water for steam generation or use it as cooling water. The difference between cooling water systems comes in how that cooling water is used (Feeley, III *et al*., 2005). In general, there are two types:

1. Once-through – these systems return the cooling water back to the ambient water body. Generally this water has had some quality alteration such as through an increase in temperature or the addition of chemicals.
2. Closed-loop – For any closed-loop system, additional water is drawn as make-up for evaporative loss however, these systems recirculate cooling water in a couple of different ways:
    i. Pond – cooling water is pumped to a pond to allow the excess heat to dissipate before the water is reused.
    ii. Cooling tower – cooling water is pumped to a cooling tower to allow the excess heat to dissipate before the water is reused.

Of next importance to total water use, where use is for cooling purposes, is the broad characterization of fuel type. In general, a nuclear station uses much more water than a thermal station. Of less importance for total water use, where use is for cooling purposes, is the style of thermal generating station and specific fuel source. For example, there are differences between water use at a coal versus natural gas and simple-cycle versus combined-cycle generating station. However, these differences, due to fuel and technology, are much less than those between a once-through station versus a closed-loop station.

Water use impacts from thermal and nuclear stations are presented in Table 7.43.

7.3.1.2 Hydroelectric

Hydroelectric generating stations have an incredible amount of water flow through the turbines in a given year. Typically, this value is equal to the entire volume of water that passes down the particular system. However, while the impacts of this water use may be significant, the impacts associated with hydroelectric generating stations are entirely different in character from those at thermal or nuclear generating stations. Typically the water does not undergo any physical quality impacts. The exception to quality impacts is the potential for dissolved oxygen impacts that are associated with supersaturation during spilling or when air is used in the turbines to avoid mechanical stress. However, these supersaturation issues can be mitigated. Of much more importance is the sometimes drastic changes to the regional hydrograph, downstream wetted area and reservoir elevations. It is the estimation of water volume impacted by these effects that must be evaluated for hydroelectric generation.

Changes to the regional hydrograph typically result in an overall levelling of water flow, particularly characterized by the loss of the spring freshet. However, while these changes often mean alterations in downstream habitat through the loss of white-water spawning and sediment build-up, it is difficult to quantify this effect broadly. Further, in many cases, particularly with water management planning and instream flow requirements during spawning periods, some of these impacts can be mitigated. As such, for the purposes of this document, hydrograph effects were not estimated.

Effects on the downstream wetted area can be daily in nature depending on how the generating plant is operated. A plant run as baseload is more likely to result in a relatively constant downstream flow. However, many hydroelectric stations are used for peaking purposes because they can rapidly ramp power output up and down thereby responding quickly to fluctuations in power demand. This results in fluctuations in downstream flow which, if there is no set minimum flow requirement, means that water output from a station can go from plant maximum to zero in a matter of hours (theoretically this fluctuation can occur over minutes but in practice this does not occur). These swings in output result in sometimes drastic changes in the

downstream wetted areas that can mean drying (and therefore loss of use) of habitat and even fish/larvae/egg stranding. Additionally, downstream velocities at peak, or near-peak, plant output can also be constraining to fish. While these effects can be large, they are site and station specific for at least two reasons. The first, and most important, reason is it depends on how the plant is operated, particularly under the agreed water management plan. It is possible that, given proper water management planning, little or no impacts will result especially during sensitive periods of the biological year (for example during spawning). The second reason is the severity of the impacts will depend on the structure of the downstream environment. For example, if a station is part of a system of stations, the backwater effects of the downstream station may mean that no changes in the wetted area occur. Consequently, for the purposes of this document, effects on the downstream wetted area were not estimated.

The final water use effect from hydroelectric generation considered for this project is changes in the reservoir elevation. For any given hydroelectric station, reservoirs are typically operated in a range of reservoir elevations. Typically this range is a few meters. These changes generally occur over the course of an operating year, although they may occur on much shorter time scales such as monthly to even weekly, and are typically planned in consultation with provincial water authorities. Although these fluctuations are typically less biologically damaging than drastic changes to the downstream wetted area, reservoir elevation levels are not typically mitigated (although they are often regulated). Further, although considerable assumptions must be made, these fluctuations provide for a number that is estimable as a litre per megawatt impact.

For the purposes of this report, the changes in reservoir elevation, and therefore volume, are used to estimate water use impacts of hydroelectric generation. By assuming a normal operating range in which the station fluctuates throughout the year, that impacts are evenly distributed throughout the reported area of the reservoir, and a vertical shoreline; water use impacts of hydroelectric operations are calculated as a maximum volume change by multiplying the reservoir area by the maximum change in elevation expected with normal operations. The assumption of vertical shoreline eliminates the need to estimate shoreline slope but underestimates the area that would be de-wetted. However, since results are reported as volume, this issue is negated. For purposes of reporting and comparison to other generation options, this water use by hydroelectric generation is reported as a water withdrawal rather than consumption. Consumption with respect to hydroelectric generation could be estimated as evaporation from the reservoir because the reservoir represents a much larger surface area than what would naturally be present. However, it was decided that this kind of analysis, while worthwhile, was beyond the scope of this document and subject to site-specific conditions such as average air temperature and wind.

It should be noted that this water use impact parameter was calculated only at two impounded hydroelectric stations, specifically Mountain Chute Generating Station (MRWMR, 2004) and the

proposed Péribonka Hydroelectric Facility (DFO, 2004). An extensive search provided no information for a pumped storage facility and, to some degree, impacts will be both similar to an impounded station and site specific. Pumped storage facilities are often placed in areas with unique characteristics such as volcano craters or mine tailing ponds. However, as stated previously, the primary impacts of a pumped storage facility is the daily fluctuation of water levels in the source and receiving water bodies. As such, a pumped storage facility will have similar impacts, on a liter per megawatt basis, as an impounded generating station. Therefore, for the purposes of this document, it will be assumed that pumped storage facilities have the same impacts as impounded reservoirs. Diversion facilities, as defined for the purposes of this document will not have water use impacts because they simply pass a portion of the water and return it. Therefore, from diversion hydroelectric generation, impacts to downstream or upstream flow are minimal.

Water use impacts from hydroelectric generation options are presented in Table 7.43.

7.3.1.3 Renewable

Wind Power

Renewable generation options, specifically wind generation, do not have any appreciable water use. Water impacts may be present during construction in the form of water crossings by access roads. However, these impacts are really site-specific and would be mitigated during the project environmental assessment.

Photovoltaics

The water requirements for PV as a generation option are negligible. As such, for the purposes of this document, water use for PV applications has been set to zero.

Fuel Cells

Data was not readily available to estimate the water requirements for fuel cell applications. It is suspected that requirements would be negligible however, this could not be confirmed.

Water use impacts from renewable generation options are presented in Table 7.43.

7.3.1.4 OMI Project

Although the OMI Project is likely to cause some impacts to water bodies during construction because of water crossings, these impacts are site specific and would require full mitigation.

Further, generation for the OMI Project is estimated in the hydroelectric generation analysis portion of this section. Therefore, OMI Project water use impacts are restricted to those resulting from generation.

Water use impacts from the OMI Project are presented in Table 7.43

TABLE 7.43 - WATER USE VALUES FOR EACH GENERATION OPTION

Generation Options	Generation Type	Reported Numbers		Typical Water Withdrawal (L/MWh)	Typical Water Consumption (L/MWh)
		Withdrawn or Total Reservoir Area	Consumed or Operating Range		
Thermal	Fossil/Biomass Once-through[1]	20 000–50 000 gallons/MWh	300 gallons/MWh	190 000	1140
	Natural gas/Oil Combined Cycle Once-through[1]	7500-20 000 gallons/MWh	100 gallons/MWh	76 000	380
	Once-through[3]	37.7 gallons/kWh	0.1 gallons/kWh	143 260	380
	Once-through[2]	140 L/kWh		140 000	-
	Fossil/Biomass Pond cooling[1]	300-600 gallons/MWh	300-480 gallons/MWh	2280	1824
	Fossil/Biomass Cooling tower[1]	500-600 gallons/MWh	480 gallons/MWh	2280	1824
	Natural gas/Oil Combined Cycle Cooling tower[1]	230 gallons/MWh	180 gallons/MWh	874	684
	Coal/Petroleum Residue Combined Cycle Cooling tower[1]	380 gallons/MWh	200 gallons/MWh	1444	760
	Recirculating[3]	1.2 gallons/kWh	1.1 gallons/kWh	4560	4180
Nuclear	Once-through[1]	60 000 gallons/MWh	400 gallons/MWh	228 000	1520
	Once-through[2]	205 L/kWh	-	205 000	-
	Pond cooling[1]	500-1100 gallons/MWh	400-720 gallons/MWh	4180	2736
	Cooling tower[1]	800-1100 gallons/MWh	720 gallons/MWh	4180	2736
Hydro-electric	Impounded – Mountain Chute	32.37km^2	4.6m	520 000	Not Estimated
	Impounded – Péribonka	31.6km[e]	1.5m	21 000	Not Estimated
	Pumped Storage			21 000 – 520 000	Not Estimated
	Diversion			0	0

		Reported Numbers			
Renewable	Wind	0	0	0	0
	Photovoltaic	0	0	0	0
OMI Project	Transmission line	0	0	0	0
	Hydroelectric Generation			21 000 – 520 000	Not Estimated
	Total			21 000 – 520 000	Not Estimated

[1] Smith *et al*., 2002.
[2] Environment Canada, 2004. Note that these numbers are only presented to show that the order of magnitude found in other sources is verified. However, because no consumption number is available, the withdrawal number will not be used.
[3] Feeley, III, *et al*., 2005.

7.3.2 Water Use Modifiers

There are two modifying factors associated with water use:

1. The presence of important biological components such as fish, commercial or sport fisheries and species at risk.

In estimating water impacts, BC Hydro (2005), also utilized the presence of fish as a modifier. In their report, they assumed that a water body with no fish was at low risk from impacts from hydro development and therefore, water impacts could be set to zero by applying a multiplier of 0. Water bodies with fish were simply multiplied by one. The same logic could be applied to other types of generation utilizing water from a water body.

For a high level assessment such as this, there is no justification for applying an additional weight to a water body that has a fishery or species at risk since these are essentially site specific issues that would be identified and mitigated during the environmental assessment stage. Therefore, while the modifiers and multipliers presented in Table 7.44 could, in principle, be used as modifiers if site specific data were available, such a weighting is not considered appropriate in this type of analysis; except with respect to the presence of fish.

TABLE 7.44
MODIFIERS AND THEIR RESPECTIVE MULTIPLIERS
FOR WATER USE IMPACTS

Modifier	Multiplier
No fish, fisheries or species at risk present	0
Fish present	1
Fisheries present	1
Species at risk present	1

2. Potentially harmful changes to the water quality during use such as temperature, dissolved oxygen or the addition of a chemical component.

In order to estimate the potential impacts of changes in the water quality, it is important to recognize that these impacts are biological and will be cumulative. Therefore, the impacts of a change in temperature, while potentially benign, may become lethal if combined with changes in dissolved oxygen or through the addition of chemical components. However, it must also be recognized that water discharge, with respect to quality, is closely regulated by both Environment Canada and the Ontario Ministry of Natural Resources. As such, any potentially

harmful discharges will require permitting that will be site specific. Therefore, no additional multiplier will be added at this stage for water quality impacts.

7.4 WASTE

To factor in the impact of waste produced as a result of electrical generation options the type and quantity of waste must be identified and represented as tonnes per kilowatt. Conventional solid or chemical wastes such as cans, cardboard, paper, newspaper, plastic, metals and glass, office or cleaning products are not factored into this model as they are common to all generation stations.

7.4.1 Extraction Waste

Similar to the experience in the Netherlands, see the ExternE document prepared by Dorland et al. (1997), extraction waste values were not readily available. It is expected that extraction waste for generation options that do not require ongoing mining for materials (such as hydroelectric and renewable generation as well as the OMI Project) will be limited to construction needs. For example, specifically associated with the OMI Project, there would be large amounts of construction related waste such as empty spools of conductor wire, excess concrete for foundations, wood waste from clearing of the right of way and general garbage created during construction. However, the extraction waste for thermal, particularly coal, and nuclear generation could result in significant tonnes per megawatt of production because of mine tailings and milling of the uranium ore. While the radiological effects of these processes are presented in the air impacts section, numbers for gross tonnage of waste material generated were not available for presentation.

Waste products can also include liquid wastes such as the oil or water-based fluids used in exploration and development drilling of natural gas wells. Depending on the type of uranium mining method used (open pit, underground or in-situ leaching), liquid wastes can include iron, sulphates, chloides, nitrates, nitrites, copper, molybdenum, zinc and calcium.[6] Coal mining also produces liquid wastes through the pumping of pit water to the surface and the leaching of material from refuse piles. Numbers for gross volume of liquid wastes are not readily available.

[6] As reported for Priargunsky mine in Siberia in *Power Generation and the Environment – A UK Perspective*. AEA Technology Environment. June 1998.

7.4.2 Operational Waste

7.4.2.1 Thermal

When considering waste generated during routine operation by thermal power technologies, it is not the technology itself that controls the production of waste but, the type of fuel. The fuel used for thermal power generation includes natural gas, synthetic gas, coal and biomass (wood waste).

Natural and Synthetic Gas

Natural gas and synthetic gas, when burned do not create waste by-products. It is recognized, however, that synthetic gas is often created by the burning of solid fuel such as coal or petroleum coke and that this gasification process will produce ash like a coal fired station. However, it is also expected that this gasification process would require separate analysis and that this analysis would result in an evaluation similar to a coal-fired thermal generating station. As such, operational waste for both natural and synthetic gas was set to zero tonnes per megawatt with the assumption that this analysis is strictly limited to burning the synthetic fuel and does not recognize the environmental impacts of its creation. Table 7.45 Presents the operational waste values.

Coal

Coal burning for electricity production produces fly ash and gypsum as waste. The Ontario Power Generation reports in their 2004 Sustainable Development Report (2004b) that the corporation diverted 91% of recovered fly ash and gypsum from landfills (see Table 7.45). OPG sells the recovered fly ash for use in binding materials (65% from Atikokan and Thunder Bay generating stations) or recycles gypsum for use in manufacturing dry wall (200,000 tonnes annually from Lambton generating station). Total ash and gypsum produced in 2004 was 950,045 tonnes with 865,624 tonnes recycled and therefore diverted from landfilling. This results in 84,421 tonnes of waste that must be landfilled annually.

Table 7.45 Presents the operation waste values for coal.

Biomass

Biomass, wood waste fuel, generates ash waste (bottom and fly) as a by-product of the energy generation. Information from a biomass generating station in Minnesota (MN EQB, 2003) indicated that ash from the generating station would be either used as a soil enhancer or landfilled. In order to estimate the production of waste from a biomass facility, contact was made with Martin Meyer (2005) at the Williams Lake Generating Station in British Columbia.

Williams Lake uses over 550,000 tons of wood waste from five nearby sawmills to generate 67-69MW of power[7] (West Bio Energy) and roughly 6.4 tonnes of ash waste are generated during this process.

Mr. Meyer (2005) indicated that while there currently exists a trial project for local farmers to utilize the ash as a substitute for agricultural lime, this has not been fully developed. As such, it should be assumed that biomass ash, on a non-site specific basis, will be landfilled.

7.4.2.2 Nuclear

The Ontario Power Generation's *Sustainable Development Report* (2004a) provides the quantity of waste by type produced at the Pickering and Darlington nuclear plants. Wastes generated during routine operation at a nuclear power plant include:

- Low-level radioactive waste in the form of clothing, mop heads, rags, paper towels and floor sweepings;
- Intermediate level waste such as used reactor components, or resins and filters to keep the reactor water systems clean;
- Used fuel bundles;
- Hazardous Wastes - liquid and solid; and
- Combustion by-products (ash and gypsum).

The quantity of low and intermediate level waste presented is provided as a volume (m^3). However, for our purposes, a tonnage estimate was required. In order to estimate this, the ratio of intermediate to low level radioactive waste was used from OPG's *Nuclear Waste Management* report (2004b) and then the tonnes of low level radioactive waste were estimated using the density of cardboard while the tonnes of intermediate level radioactive waste were estimated using the density of iron. From the reported 1979m^3 of low and intermediate level waste that was stored in 2004 the estimated tonnage is 1958 tonnes.

To provide consistency with reported numbers for thermal generation, only the stored nuclear waste is reported. Waste quantities (as reported for 2004) are presented in Table 7.45.

[7] The plant is actually rated to produce 60MW_e of net electricity but since it began production in 1995 has consistently had an annual capacity factor near or greater than 100% and is capable of producing 67-69MW net (West Bio Energy).

7.4.2.3 Hydroelectric

There are no waste products requiring storage or disposal as a result of routine operation of a hydroelectric station.

7.4.2.4 Renewable

Wind Power

There are no waste products requiring storage or disposal as a result of routine operation of a wind farm.

Photovoltaic

Waste production during PV operations would negligable. As such, for the purposes of this report the value was set to zero.

Fuel Cell

Data was not readily available to estimate the waste generated during fuel cell operation. It is suspected that waste creation would be negligible however, this could not be confirmed.

7.4.2.5 OMI Project

There are no waste products requiring storage or disposal that are generated as a result of routine operation of a transmission line.

TABLE 7.45
WASTE GENERATED DURING ROUTINE OPERATION AT EACH DIFFERENT GENERATION OPTION.

Generation Option	Generation Type	Waste Type	Quantity (tonnes)	Megawatt	Value (tonnes/MW)	
Thermal	Natural Gas	None	0	-	0	
	Synthetic Gas	None	0	-	0	
	Coal	Ash and Gypsum (not recycled or sold)	84,421	7560	11.2	
	Biomass	Fly and bottom ash	6.4	60	0.11	
Nuclear	CANDU	Low, Intermediate stored	1958	6103	0.32	0.52
	CANDU	Used fuel in storage	1216	6103	0.20	
Hydroelectric	Impounded, Pumped Storage or Diversion	None	0	-	0	
Renewable	Wind	None	0	-	0	
	Photovoltaic	None	0	-	0	
OMI Project	Transmission line	None	0	-	0	
	Hydroelectric	None	0	-	0	
	Total	None	0	-	0	

7.4.3 Waste Modifiers

With respect to waste impacts of generation options, there are three potential modifying factors:

1. Permanence of the storage facility - Waste generated by any generation option will either be disposed in a landfill (ash, gypsum), or stored in a long term waste facility (used radioactive fuel bundles and low and intermediate waste). In this evaluation, consideration was given to the permanence of a landfill facility or a long term storage facility for radioactive material. For an engineered landfill facility we have assumed a 25-year lifespan followed by 100 years[8] of leachate and methane gas monitoring and treatment. The land use continues to be impaired once the landfill site is closed, as most built forms are prohibited[9]. However, landfills can be used as urban green space or re-vegetated to provide wildlife habitat.

[8] Based on modelling conducted for the Notre Adams Mine Environmental Assessment (SENES, 1996)
[9] There are examples of ski hills being developed on a closed landfill site mound.

The lifespan of a long-term storage facility for radioactive waste is tens-of-thousands of years. The newly formed Nuclear Waste Management Orgaization (NWMO) seeks a long-term approach for managing used nuclear fuel produced by Canada's electricity generators. According to the NWMO (2005), the technical method being proposed is for centralized containment and isolation of used nuclear fuel deep underground in suitable rock formations. The centralized management facility is based on a multi-barrier concept (engineered and natural) and would include a monitoring program. This type of regulated facility involves the encapsulation of used fuel in engineered containers and then placed and sealed in excavated rooms in naturally occurring geological formations. The storage chambers are designed at a depth of 500 to 1000m below the ground surface. Several interim facilities currently exist at existing nuclear power stations such as Bruce Power and at Chalk River, Ontario and Whiteshell Laboratories, Manitoba, to manage the existing waste and waste in the foreseeable future. Human health impacts associated with waste storage from nuclear plants are represented in potential radioactive doses. This impact is discussed and quantified in the air impact section.

From a land use perspective, both an engineered landfill and an intermediate or long-term storage facility for radioactive materials, impaires land use over the long-term. A closed landfill site can be vegetated to provide wildlife habitat, as can the land above the below ground storage facility and its associated above ground building. With a planning horizon of a minimum 100 years (municipal official plans cover a 20 year planning horizon), neither the landfill nor the long-term storage site are available for use other than revegetated to provide wildlife habitat. Therefore, it is not possible to distinguish between the permanency of the two waste disposal facilities and no modifying factor was developed.

2. Engineering cost - Both waste facilities will be engineered to prohibit any adverse environmental impacts and both facilities must meet provincial and/or federal design requirements prior to receiving operational approvals. Further, economic criteria, such as engineering costs, are beyond the scope of this methodology.

3. Potential environmental or human health impacts - Societal values/public perception toward radioactive waste is that long-term storage of radioactive materials for tens-of-thousands of years poses a significant threat to public health and safety as well as natural environment contamination. However, by comparison, landfill leachate poses a significant threat to groundwater as a result of escaped landfill leachate. Further, radioactive waste storage containers are specifically designed and sealed such that public doses are only a small fraction above background.

A comparison of the relative potential impacts of a landfill versus a long-term storage facility for radioactive waste is not readily available and quantification of this kind of impact is beyond the scope of this document. As such, it is difficult to assign a modifying value to potential

environmental or human health impacts from either type of storage facility and therefore, no modifying factor was developed to evaluate potential differences between environmental or human health impacts.

7.4.4 Decommissioning Waste

Decommissioning waste for any generation option is a composition of the material used for the physical structures and facilities associated with the option. For example, wind as a generation option essentially amounts to the metal and concrete utilized for the turbine, internal motor, generator and footing. Likewise, for hydroelectric as a generation option, it is the concrete and metal associated with the dam, the powerhouse, penstocks, turbines, and generators that make up the decommissioning waste. It is important to note that most of this material is recyclable and will be re-used.

According to the ExternE national Implementation Report for the Netherlands (Dorland *et al.,* 1997), there is limited experience world-wide in the decommissioning of nuclear facilities. However, radiological emissions resulting from decommissioning a plant are discussed as part of the air quality section.

Decommissioning waste for PV as a generation option is suspected to result in the largest impacts in the life-cycle of PV. However, there is very little data on decommissioning waste since the technology is very new. It is anticipated that many of the components can be recycled. The (lead-acid) battery is primarily responsible for the environmental impacts of solar home systems. It is also possible that heavy metal leaching from some modules may exceed environmental limits.

The actual numbers to compare the tonnes of waste generated through decommissioning of a generating option on a per megawatt basis were not readily available.

7.5 SUSTAINABILITY

There are a number of attributes that contribute to the sustainability of any project. The British Columbia Round Table on the Environment and the Economy presented a summary of these in 1992:

1. Limit the impact of generation on the environment.
2. Maintain the natural environment.
3. Minimize the use of non-renewable resources.
4. Ensure and enhance the efficient use of resources that are currently being used for electrical generation.

5. Ensure that the costs and benefits of energy production on the environment and to resource use are distributed fairly while meeting basic requirements.
6. Ensure that sustainability is considered when making policy and decisions.
7. Promote sustainability in the public.

It is hoped that the methodology presented in this document will work towards maintaining and limiting the impact to the natural environment of electrical generation. The efficient use of resources is practical not only from the sustainable but, also from the economic point of view. Fair distribution of costs and benefits falls under both a siting issue and a policy determination. Sustainability into policy and decisions and the promotion of sustainability through conservation efforts is directly tasked to OPA as part of the authority's objectives. This leaves the issue of minimizing the use of non-renewable resources for electricity production as part of the overall sustainability picture.

When evaluating how to bring the issue of sustainability into the current model, three items were considered:

1. Generation efficiency – different generation options have different efficiency at producing power from the source energy.
2. Facility life – different generation options have different expected life expectancies.
3. Renewability of the fuel source – fairly straightforward accounting of fuel use versus how much is available for future use.

However, it was decided that efficiency was considered not only during the economic analysis of a generation option, but would also be included in the assessment of impacts to air. Particularly because efficiency would be included as part of air impacts and there was a desire to avoid double accounting, it was decided that generation efficiency would not be included as part of sustainability accounting.

The question of facility life as a measure of sustainability is an interesting one. It is also complicated by questions such as whether a refurbished hydroelectric turbine constitutes a 'new' facility or simply a measure to extend the life of an old facility. Presumably, with constant technological upgrades, any facility could have a near endless – or at least unestimable – life expectancy. Consequently, facility life can not be included as a measure of sustainability.

The final factor identified, both in this process and the BC Round Table process, is the renewability of the fuel source. Not only is this factor easily defensible as an indicator of sustainability, it is also relatively definable and qualitatively measureable. Consequently, in order to assess the sustainability of generation options, only the renewability of the fuel source would be assessed.

In assessing the renewability of any given generation option, the assumption was made that finite resources can be evaluated against one another based on the amount that is still available for exploitation. In this sense, it is possible to then determine how much longer a finite resource can be expected to last, giving a measure of sustainability. This allows for a finite resource to be ranked based on the premise that there is more of some finite resources than others, particularly with respect to their associated consumptive rates.

7.5.1 Thermal

Natural Gas

Canada is the world's third-largest natural gas producer and second-largest gas exporter and the natural gas industry is very important to the Canadian economy. Canada produces essentially all of the gas used by Canadians, as well as producing large quantities for export to the U.S. Natural gas resources are divided into categories: established reserves; discovered resources; undiscovered conventional resources; and undiscovered unconventional resources. Combining these categories, the total remaining resources for Canada are estimated at 630Tcf or 17.8 trillion m^3. Most natural gas production (88%) comes from wells classified as gas wells with the remaining 12% coming from oil wells. Canadian natural gas production almost doubled between 1988 and 1998, reaching 167 billion m^3 in 1998. (NRC, 2002b).

According to NRCan's Canada Energy Outlook 1996-2020, Canadian gas demand is projected to increase from 79 billion m^3 in 1997 to between 127 and 150 billion m^3 by 2020. Total Canadian gas production is forecast to increase from 167 billion m^3 in 1997 to between 227 and 255 billion m^3 by 2010 (NRC, 2002b). At maximum estimated 2010 production, there is an expected 70 years of production remaining.

Coal

Canada is richly endowed with coal and holds about 1% of the world's coal resources. Thermal coal (steam coal) is used primarily to generate electricity. Coal is an essential part of Canada's energy sector, with 90% of domestic coal consumption used in electricity generation. Canada's coal resources are widely distributed. Recoverable coal reserves, approximately 6.5 billion tonnes, represent only a small portion of Canada's total coal resources. Coal exports are projected to increase from 34 million tonnes in 1995 to 37 million tonnes in 2020. Domestic coal demand is expected to increase from 53 million tonnes in 1995 to 74 million tonnes in 2020 (NRC, 2002a).

Roughly 100 years remain for coal production from established reserves. If all coal resources of immediate interest are considered, at least 1000 years of production remain (NRC, 2002a).

Biomass

Bioenergy is produced from the conversion of biomass in the form of wood, wood waste from manufacturing activities, agricultural products and residues, or municipal wastes. Bioenergy is the most important source of renewable energy after hydroelectricity. Production comes mainly from the combustion of waste from forest products and pulp and paper industries to generate steam for their own use (NRC, 2002c).

There are two major sources of industrial wood waste – saw mills (which produce chips, saw dust and bark); and pulping liquor (mixture of water, pulping chemicals and organic matter which bonds wood fibres together). Mill residues are estimated around 19 million dry tonnes a year, of which 10 million tonnes are used either for products or energy, with the rest being disposed of in landfills. Energy use of wood waste and pulping liquor by Canadian manufacturing industry amounted to 493 PJ in 1997. The largest user of industrial biomass is the pulp and paper industry (NRC, 2002c).

Some of the wood waste is used to generate electricity. The pulp and paper industry has about 1000 MW of electricity generating capacity. Some independent power producers generate electricity from the combustion of wood waste. About 10 plants in Canada produce electricity to sell to electric utilities, with a total installed capacity of about 200 MW (NRC, 2002c).

7.5.2 Nuclear

Uranium is a common elements in the earth's crust. Small masses of fissile uranium can release enormous amounts of energy by means of nuclear fission. Complete fission of uranium (isotope U235) can produce 2.5 million times more heat than the combustion of an equal weight of carbon in wood, coal or natural gas. Uranium is used mainly to fuel nuclear reactors, where energy released from a controlled fission reaction is used to generate electricity. Canada is the world's leading producer of uranium. In 1997 Canadian uranium production amounted to more than 12000 tonnes of uranium, approximately 1/3 of total global production. Canada has significant uranium resources of current economic interest. As of January 1, 1998 total recoverable uranium resources in Canada were estimated at 419 000 tonnes of uranium. At 1998 rates, this was equal to about 40 years of production. However, there is significant potential for discovering more uranium resources in Canada (NRC, 2002d).

Other estimates of years of remaining production for uranium were made from world uranium reserves and consumption were estimated from the World Energy Council (2005) at 172 years and the Canadian Nuclear FAQ (2005) at 250 years.

7.5.3 Hydroelectric

Hydroelectric energy is a renewable energy source and is the main source of electricity in Canada, representing nearly two-thirds of all electricity produced. Canada is the world leader of hydroelectricity production with an installed generating capacity totalling 67,121 MW in 2002. Looking to the future, there is significant potential for additional hydroelectricity production in Canada with an estimated potential of 182,832 MW (CanREN, 2003).

The Canadian Electricity Association (CEA) stated (CanREN, 2003):

> "When most of us in the United States and Canada think of renewable energy, we think of emerging technologies like solar, wind, geothermal or biomass. In doing so, we take for granted the predominant form of renewable energy – hydropower…
>
> …While all of these renewables promise significant long-term opportunity, the pre-eminent renewable generating technology today and for the foreseeable future, is hydroelectricity. Whatever form that support for emerging renewable takes, the fact remains that hydro power is an established renewable technology that offers the environmental benefits associated with emerging renewable competitors at a cost-effective price, with dependable supply, and the added benefit of opportunities for continued expansion."

7.5.4 Renewable

Renewable energy refers to several energy sources that produce electricity or thermal energy without depleting resources. Renewable energy sources include biomass, earth, solar, water, waste stream energy, and wind. With approximately 17 percent of the country's primary energy supply coming from renewable energy sources, Canada is a world leader in the production of renewable energy. However, included in this total is hydroelectricity, representing 11 percent and biomass energy, representing 6 percent of Canada's primary energy supply. Renewable energy production will continue to grow in Canada (NRC, 2002c).

7.5.5 OMI Project

For the OMI Project, apart from the hydroelectric generation portion, the resource that is really being utilized is land. In Canada, the argument could be made that land is essentially infinite in abundance however, there are areas of Canada, particularly in the southern halves of all provinces, including Ontario, where land is a limited resource. Therefore, it was determined that for this project, land would be considered a finite resource. The task became determining how many "years of production" remained in Ontario for a project the size of the OMI Project.

In order to estimate the years of production based on the land required for the OMI Project, numbers were obtained from MNR (2001). For forest management purposes, Ontario MNR divides the province into four basic areas, the Northern Boreal (41.9%), the Great Lakes (7.7%), Southern Ontario (7.7%) and the Planning Area (42.1%). The Planning Area is largely central Ontario and it was decided that this is the area that would most likely be utilized for a large transmission project (either the OMI Project or any future interconnection with Quebec). As such, in order to estimate the area that may eventually see transmission development, a sum was made of the land found in the Planning Area and Southern Ontario. From this land, the area that is currently allocated to parks was subtracted since it seemed unlikely that routing through a park area would be feasible.

The final number gave an estimated available land area of 481, 340 km^2. It is noted that this number is still an overestimation of the land that is likely to be developed for a large transmission project. Not only does it include area in the middle of Ontario that is not likely to ever be considered for routing, it also does not subtract privately held land, particularly in southern Ontario, that could be subject to strong public opposition.

7.5.6 Sustainability Criteria Values

Table 7.46 provides the values for sustainability for the different generation options.

TABLE 7.46
SUSTAINABILITY ASSESSMENT FOR GENERATION OPTIONS

Generation Option	Fuel	Renewability of Fuel	Estimated Years of Production Remaining
Thermal	Natural Gas	Finite	70
	Coal	Finite	500[3]
	Biomass	Infinite	N/A
Nuclear	Uranium – Canada (NRC, 2002)	Finite	40
	Uranium – World (WEC, 2005)	Finite	172
	Uranium – World (Can Nuclear FAQ, 2005)	Finite	250
Hydroelectric	Water	Infinite[1]	N/A
Renewable	Wind	Infinite	N/A
	Solar	Infinite	N/A
OMI Project	Land[2]	Finite	5348
	Water	Infinite	N/A
	Total	N/A	N/A

[1] It may be argued that water, especially freshwater, as a valuable resource for other uses, is not in infinite supply. This is particularly true in the face of expected climate change impacts. However, it is expected that any constraints on water use will be dealt with at the environmental assessment and water use planning stage on a site specific basis.
[2] Assessing the sustainability of a transmission line as a generation option presented some comparison difficulty. However, if the assumption is that the resource being impacted is primarily land, a comparison can be done. In this sense then, similar to water, an argument can be made that land is not in infinite supply
[3] In estimating the years of production for coal it was noted that while there is 100 years of proven reserves are available but an estimate 1000 years of "immediate interest" reserves exist. Therefore, an estimate of 500 years was used for this project.

8.0 ENVIRONMENTAL CRITERIA RANKING

8.1 AIR IMPACTS

8.1.1 Emissions of Conventional Contaminants

The normalized emission factors for each technology were assigned a relative rank from 1-10. The maximum normalized life-cycle air emission rate from all of the technologies is from cyclone coal generation, with 4.4 kg/MWh. The following ranking scheme was developed to apply to the normalized contaminant emission rates:

Table 8.1 Rank Values for Normalized Contaminant Emission Rates

Rank	Normalized Emission Rate (kg/MWh)
0	0-<0.1
1	0.1-0.4
2	0.5-0.9
3	1.0-1.3
4	1.4-1.8
5	1.9-2.2
6	2.3-2.6
7	2.7-3.1
8	3.2-3.5
9	3.6-3.9
10	4.0-4.4

These ranks were applied to the normalized emissions for each technology. For ease of reference the normalized life-cycle contaminant emission rates for each technology (as presented previously in Chapter 7) are presented in addition to the rankings for each fuel alternative.

Natural Gas Fuel Cycle

Table 8.2 Normalized Contaminant Emission Rates (kg/MWh) from Natural Gas Fuel Cycle

	70% cogen	60% combined	50% combined	40% single	30% single	20% single
Natural Gas Generation Water-Steam Injection	0.6	0.7	0.8	1.0	1.3	2.0
Natural Gas Generation Dry-Low NOx	0.5	0.6	0.7	0.9	1.1	1.7
Landfill Gas - Power Generation	0.9	1.0	1.2	1.5	2.0	3.0
Digester Gas - Power Generation	0.7	0.8	1.0	1.3	1.7	2.5

Table 8.3 Ranking for Contaminant Emissions – Natural Gas Fuel Cycle

	70% cogen	60% combined	50% combined	40% single	30% single	20% single
Natural Gas Generation Water-Steam Injection	2	2	2	3	3	5
Natural Gas Generation Dry-Low NOx	2	2	2	2	3	4
Landfill Gas - Power Generation	2	3	3	4	5	7

Digester Gas - Power Generation	2	2	3	3	4	6

Coal Fuel Cycle

Table 8.4 Normalized Contaminant Emission Rates (kg/MWh) from Coal Fuel Cycle

		Low NO_x Burner				Low NOx Burner+Post Burner Control			
		35%	40%	50%	60%	35%	40%	50%	60%
Pulverized Coal		3.3	2.9	2.3	1.9	2.1	1.8	1.4	1.2
Cyclone		4.4	3.8	3.1	2.6	2.2	2.0	1.6	1.3
Stoker		2.7	2.3	1.9	1.6	1.9	1.6	1.3	1.1
Fluidized Bed	circulating	1.0	0.9	0.7	0.6	0.6	0.6	0.4	0.4
Fluidized Bed	bubbling	2.4	2.1	1.7	1.4	1.2	1.1	0.9	0.7

Table 8.5 Ranking for Contaminant Emissions – Coal Fuel Cycle

		Low NOx Burner				Low NOx Burner+Post Burner Control			
		35%	40%	50%	60%	35%	40%	50%	60%
Pulverized Coal		8	7	6	5	5	5	4	3
Cyclone		10	9	7	6	5	5	4	3
Stoker		6	6	5	4	5	4	3	3
Fluidized Bed	circulating	3	2	2	2	2	2	1	1
Fluidized Bed	bubbling	6	5	4	4	3	3	2	2

Coal Gasification Fuel Cycle

Table 8.6 Normalized Contaminant Emission Rate (kg/MWh) and Ranking for Coal Gasification Fuel Cycle

Conventional Emissions	Normalized Emission Rate (kg/MWh)	Rank
Wabush River Coal Gasification Project	1.6	4

Biomass Fuel Cycle

Table 8.7 Normalized Contaminant Emission Rate (kg/MWh) and Ranking for Biomass Fuel Cycle

	Normalized Emission Rate (kg/MWh)	Rank
WCF (Coal Plant - Biomass Portion)	0.5	2
WG-Plant (Gasification Plant)	0.8	2

Nuclear Fuel Cycle

Table 8.8 Normalized Contaminant Emission Rate (kg/MWh) and Ranking for Nuclear Fuel Cycle

Conventional Emission (kg/MWh)	Normalized Emission Rate (kg/MWh)	Rank
Average BWR	0.4	1
Advanced BWR	0.3	1

Note: for present purposes, all reactors are considered the same.

Hydroelectric Cycle

Table 8.9 Normalized Contaminant Emission Rate (kg/MWh) and Ranking for Hydroelectric Cycle

Conventional Emissions	Normalized Emission Rate (kg/MWh)	Rank
Hydroelectric Cycle	0.07	0

Wind Power Cycle

Table 8.10 Normalized Contaminant Emission Rate (kg/MWh) and Ranking for Wind Power Cycle

Conventional Emissions	Normalized Emission Rate (kg/MWh)	Rank
Wind Power Cycle	0.15	1

Photovoltaic Cycle

Table 8.11 Normalized Contaminant Emission Rate (kg/MWh) and Ranking for Wind Power Cycle

Conventional Emissions	Normalized Emission Rate (kg/MWh)	Rank
Photovoltaic Cycle	1.9	5

8.1.2 Greenhouse Gases

The global warming potential (GWP) for each technology were similarly assigned a relative rank from 1-10. The maximum GWP are from coal generation, and the maximum estimated emission rate is 1.14 kg/MWh, therefore the following ranking scheme was developed:

Table 8.12 Rank Values for Global Warming Potential

Rank	Global Warming Potential
0	0-<0.01
1	0.01-0.11
2	0.12-0.23
3	0.24-0.34
4	0.35-0.45
5	0.46-0.57
6	0.58-0.68
7	0.69-0.79
8	0.80-0.91
9	0.92-1.02
10	1.03-1.14

As for air emissions of conventional contaminants, for each energy alternative, both the emissions and the rankings are provided.

Natural Gas Fuel Cycle

Table 8.13 Global Warming Potential (Tonnes CO_2-eq /MWh) for Natural Gas Fuel Cycle

Fuel	70%	60%	50%	40%	30%	20%
	cogen	combined	combined	single	single	single
Natural Gas	0.25	0.29	0.35	0.44	0.59	0.88
Landfill Gas	0	0	0	0	0	0
Digester Gas	0.15	0.18	0.22	0.27	0.36	0.54

Table 8.14 GWP Ranking for Natural Gas Fuel Cycle

Fuel	70%	60%	50%	40%	30%	20%
	cogen	combined	combined	single	single	single
Natural Gas	3	3	4	4	6	8
Landfill Gas	0	0	0	0	0	0
Digester Gas	2	2	2	3	4	5

Coal Fuel Cycle

Table 8.15 Global Warming Potential (Tonnes CO_2-eq /MWh) for Coal Fuel Cycle

		GWP (Tonnes CO_2-eq /MWh)			
		35%	40%	50%	60%
Pulverized Coal		0.96	0.85	0.70	0.59
Cyclone		0.96	0.85	0.70	0.59
Stoker		0.96	0.85	0.69	0.59
Fluidized Bed	circulating	1.14	1.00	0.82	0.70
Fluidized Bed	bubbling	1.14	1.00	0.82	0.70

Table 8.16 GWP Ranking for Coal Fuel Cycle

		Rank			
		35%	40%	50%	60%
Pulverized Coal		9	8	7	6
Cyclone		9	8	7	6
Stoker		9	8	7	6
Fluidized Bed	circulating	10	9	8	7
Fluidized Bed	bubbling	10	9	8	7

Coal Gasification Fuel Cycle

Table 8.17 Global Warming Potential (Tonnes CO_2-eq /MWh) and Rank for Coal Gasification Fuel Cycle

GHG Global Warming Potential (Tonnes CO_2-eq /MWh)	Tonnes CO_2eq/MWh	Rank
Without CO2 removal	0.98	9
Chemical Absorption (83% removal)	0.36	4
CO2 removal (90% removal)	0.30	3

Biomass Fuel Cycle

Table 8.18 Global Warming Potential (Tonnes CO_2 eq /MWh) for Biomass Fuel Cycle

	WCF (Coal Plant - Biomass Portion)	WG-Plant (Gasification Plant)
CO2 Total	1.10	1.10
CO2 Considering Biomass Growth	0.07	0.06

Table 8.19 GWP Rank for Biomass Fuel Cycle

	WCF (Coal Plant - Biomass Portion)	WG-Plant (Gasification Plant)
CO2 Total	10	10
CO2 Considering Biomass Growth	1	1

Nuclear Fuel Cycle

Table 8.20 Global Warming Potential (Tonnes CO_2-eq /MWh) and Rank for Nuclear Fuel Cycle

GHG Global Warming Potential	Tonnes CO_2eq/MWh	Rank
Average BWR	0.012	1
Advanced BWR	0.009	0
BWR and PWR light water reactor	0.005-0.012	1

Hydroelectric Fuel Cycle

Table 8.21 Global Warming Potential (Tonnes CO_2-eq /MWh) and Rank for Hydroelectric Cycle

Total CO_2 Eq Emissions	T CO_2-eq/MWh	Rank
Rock Filled Dam - Run of River	0.003	0
Concrete Dam - Run of River	0.020	1
Rock Filled Dam - Reservoir	0.016	1
Concrete Dam - Reservoir	0.033	1

Wind Power Cycle

Table 8.22 Global Warming Potential (Tonnes CO_2-eq /MWh) and Rank for Wind Power Cycle

	Tonnes CO_2-eq/MWh	Rank
Construction	0.012	1

Photovoltaic Power Cycle

Table 8.23 Global Warming Potential (Tonnes CO_2-eq /MWh) and Rank for Wind Power Cycle

	Tonnes CO_2-eq/MWh	Rank
Construction	0.531	5

8.1.3 Radioactivity Emissions

The normalized collective effective life-cycle doses for each technology were assigned a relative rank from 1-10 in the same manner as the conventional pollutant releases. Following the UNSCEAR concept of collective dose, the maximum collective effective dose is from coal mining (20 person Sv.GW a), therefore the following ranking scheme was developed:

Table 8.24 Rank Values for Normalized Collective Effective Dose

Rank	Normalized Collective Effective Dose (person Sv/GWa)
0	0
1	0.1-2.0
2	2.1-4.0
3	4.1-6.0
4	6.1-8.0
5	8.1-10.0
6	10.1-12.0
7	12.1-14.0
8	14.1-16.0
9	16.1-18.0
10	18.1-20.0

Natural Gas Fuel Cycle

Table 8.25 Normalized Collective Effective Dose (person Sv/GWa) and Rank from Natural Gas Fuel Cycle

	Normalized Collective Effective Dose (person Sv/GWa)	Rank
Gas Fired Power Plant	0.03	0

Coal Fuel Cycle

Table 8.26 Normalized Collective Effective Dose (person Sv/GWa) and Rank from Coal Fuel Cycle

	Normalized Collective Effective Dose (person Sv/GW a)	Rank
Coal Fuel Cycle	20[1]	10

Nuclear Fuel Cycle

Table 8.27 Normalized Collective Effective Dose (person Sv/GWa) and Rank from Nuclear Fuel Cycle

Life-Cycle Normalized Collective Dose	Normalized Collective Effective Dose (person Sv/GW a)	Rank
Pressurized Water Reactor (PWR)	8.4	5
Boiling Water Reactor (BWR)	9.0	5
Heavy Water Reactor (HWR)	10.7	6

As noted previously, with respect to radioactive emissions and dose, for practical purposes there is no difference in the doses and ranks between the nuclear alternatives. Nonetheless, for

consistency, the nominal differences in ranking indicated above si carried through the assessment.

8.2 LAND IMPACTS

The land use ranking is calcualated by multiplying the permanence of impacts multiplier identified in section 7.2.2 with the land use value identified in Table 7.1 in section 7.2.1. The final values are presented in Table 8.28.

TABLE 8.28
FINAL VALUES FOR LAND USE BY GENERATION OPTION

Generation Option	Generation Type	Proposed or Existing Station	Land Use Estimate (km^2/MW)	Permanance Multiplier	Total
Thermal	Natural Gas	Goreway	0.00025	0.85	0.00021
	Natural Gas	Portlands	0.00021	0.85	0.00018
	Natural Gas	Brighton Beach	0.00017	0.85	0.00014
	Coal/Synthetic Gas	Mesaba	0.0067	0.85	0.0057
	Biomass	Saint John	0.0044	0.85	0.0037
	Biomass	NGPP Minnesota	0.014	0.85	0.012
Nuclear	CANDU	Pickering	0.00051	0.85	0.00043
	CANDU	Darlington	0.0014	0.85	0.0012
	CANDU	Bruce	0.0029	0.85	0.0025
Hydro	Impounded	Romaine	0.18	0.7	0.13
	Impounded	Péribonka	0.082	0.7	0.057
	Impounded	Mountain Chute	0.19	0.7	0.13
	Pumped Storage		0	0.7	0
	Diversion		0	0.7	0
Renewable	Wind	Wolfe Island	0.10-0.21	0.7	.070-.15
	Wind	Melancthon Grey	0.15	0.7	0.10
	PV		0.0013	1	0.0013
OMI Project	Transmission Line		0.09	0.85	0.13
	Hydro Generation		0.082-0.19	0.7	0.057-0.13
	OMI Project Total		0.17-0.28	0.85 & 0.7	0.18-0.26

The final ranking of these values from 0-10 simply assigns the highest number to the most land used after modifying effects (0.26 for the OMI Project total) and the lowest number to the least land used after modifying effects (zero for hydroelectric generation pumped storage and diversion). There is no justification to separate the rankings any way other than equally and therefore, land use ranking increments are by 0.02878km^2/MW and becomes as presented in Table 8.29. Note that values have been rounded to four significant digits where applicable.

TABLE 8.29
RANKING VALUES FOR LAND USE

Criteria – Land Use (km^2/MW)	Rank
0	0
.00001 – 0.02878	1
0.02879 – 0.05756	2
0.05757 – 0.08633	3
0.08634 – 0.1151	4
0.1152 – 0.1439	5
0.1440 – 0.1727	6
0.1728 – 0.2014	7
0.2015 – 0.2302	8
0.2303 – 0.259	9
≥0.26	10

In cases where more than one rank can be applied to a generation option, the ranks will be averaged. Table 8.30 presents the final rankings for each of the generation options.

TABLE 8.30
FINAL RANKINGS FOR LAND USE FOR EACH GENERATION OPTION

Generation Option	Generation Type	Proposed or Existing Station	Land Use Estimate (km^2/MW)	Land Use Estimate with Modifier (km^2/MW)	Ranking	Generation Option Ranking
Thermal	Natural Gas	Goreway	0.00025	0.00021	1	1
	Natural Gas	Portlands	0.00021	0.00018	1	
	Natural Gas	Brighton Beach	0.00017	0.00014	1	
	Coal/Synthetic Gas	Mesaba	0.0067	0.0057	1	1
	Biomass	Saint John	0.0044	0.0037	1	1
	Biomass	NGPP Minnesota	0.014	0.012	1	
Nuclear	CANDU	Pickering	0.00051	0.00043	1	1
	CANDU	Darlington	0.0014	0.0012	1	
	CANDU	Bruce	0.0029	0.0025	1	
Hydro	Impounded	Romaine	0.18	0.13	5	4
	Impounded	Péribonka	0.082	0.057	2	
	Impounded	Mountain Chute	0.19	0.13	5	
	Pumped Storage		0	0	0	0
	Diversion		0	0	0	0
Renewable	Wind	Wolfe Island	0.10-0.21	.070-.15	3-6	4.5
	Wind	Melancthon Grey	0.15	0.10	4	
	PV		0.0013	0.0013	1	1
OMI Project	Transmission Line		0.15	0.13	5	5
	Hydro Generation		0.082-0.19	0.057-0.13	2-5	4
	OMI Project Total		0.23-0.34	0.18-0.26	7-10	8.5

8.3 WATER IMPACTS

From the values identified in section 7.3, specifically Table 7.5, and the multiplier identified in section 7.3.2, the final values are calculated and presented in Table 8.31. It can also be assumed, unless otherwise indicated on a site-specific basis, that fish are present in water bodies that are likely to be developed for electric generation. Therefore, for all generation options, the fish, commercial and sport fisheries and species at risk multiplier is one.

TABLE 8.31
FINAL WATER USE IMPACT VALUES

Generation Option	Generation Type	Fish Presence Multiplier	Water Withdrawal (L/MWh)	Water Consumption (L/MWh)
Thermal	Fossil/Biomass Once-through	1	190 000	1140
	Natural gas/Oil Combined Cycle Once-through	1	76 000	380
	Once-through	1	143 260	380
	Once-through	1	140 000	-
	Fossil/Biomass Pond cooling	1	2280	1824
	Fossil/Biomass Cooling tower	1	2280	1824
	Natural gas/Oil Combined Cycle Cooling tower	1	874	684
	Coal/Petroleum Residue Combined Cycle Cooling tower	1	1444	760
	Recirculating	1	4560	4180
Nuclear	Once-through	1	228 000	1520
	Once-through	1	205 000	-
	Pond cooling	1	4180	2736
	Cooling tower	1	4180	2736
Hydroelectric	Impounded – Mountain Chute	1	520 000	Not Estimated
	Impounded – Péribonka	1	21 000	Not Estimated
	Pumped Storage	1	21 000 – 520 000	Not Estimated
	Diversion	1	0	0
Renewable	Wind	1	0	0
	Photovoltaic	1	0	0
OMI Project	Transmission line	1	0	0
	Hydroelectric Generation	1	21 000 – 520 000	Not Estimated
	Total	1	21 000 – 520 000	Not Estimated

From these values, it is possible to assign a ranking from 1-10 of possible water use impacts from generation options for both water consumption and water withdrawal. It was determined that both of these factors are equally important from a water use impacts perspective for thermal and nuclear stations.

From the information presented, it is clear that wind represents the least impacts to water resources in either factor. Therefore, a zero impact for both consumption and withdrawal was given a rank of zero.

For the rankings in between one and ten for water withdrawal, there was no justification for dividing in any other way than equally. The highest withdrawal value found was 520,000 L/MWh. Thus, dividing equally, each rank is separated by 57,777 L/MWh to produce the rankings found in Table 8.32.

TABLE 8.32
RANKING VALUES FOR WATER WITHDRAWAL

Criteria – Water Withdrawal (L/MWh)	Rank
0	0
1 – 57 777	1
57 778 – 115 555	2
115 556 – 173 333	3
173 334 – 231 110	4
231 111 – 288 888	5
288 889 – 346 666	6
346 667 – 404 443	7
404 444 – 462 221	8
462 222 – 519 999	9
≥ 520 000	10

For the rankings in between one and ten of water consumption, there was no justification for dividing in any other way than equally. The highest consumption value found was 4180 L/MWh. Thus, dividing equally, each rank is separated by 464.33 L/MWh to produce the rankings found in Table 8.33. Note that these rankings have actually been rounded to the nearest whole number where applicable.

TABLE 8.33
RANKING VALUES FOR WATER CONSUMPTION

Criteria – Water Consumption (L/MWh)	Rank
0	0
1 - 464	1
465 - 929	2
930 - 1393	3
1394 – 1857	4
1858 – 2322	5
2323 – 2786	6
2787 – 3250	7
3251 – 3715	8
3716 – 4179	9
≥ 4180	10

For the final ranking of water use, an average is used of the rank for water consumption and for water withdrawal in order to capture both effects for each generation option. These final rankings are presented in Table 8.34.

TABLE 8.34
FINAL RANKINGS FOR WATER USE IMPACTS FROM EACH GENERATION OPTION

Generation Option	Generation Type	Water Withdrawal (L/MWh)	Water Consumption (L/MWh)	Ranking – Water Withdrawal	Ranking – Water Consumption	Generation Option Ranking
Thermal	Fossil/Biomass Once-through	190 000	1140	4	3	3.5
	Natural gas/Oil Combined Cycle Once-through	76 000	380	2	1	1.5
	Once-through	143 260	380	3	1	2
	Once-through	140 000	-	3	-	
	Fossil/Biomass Pond cooling	2280	1824	1	4	2.5
	Fossil/Biomass Cooling tower	2280	1824	1	4	2.5
	Natural gas/Oil Combined Cycle Cooling tower	874	684	1	2	1.5
	Coal/Petroleum Residue Combined Cycle Cooling tower	1444	760	1	2	1.5
	Recirculating	4560	4180	1	10	5.5
Nuclear	Once-through	228 000	1520	5	4	4.25
	Once-through	205 000	-	4	-	
	Pond cooling	4180	2736	1	5	3
	Cooling tower	4180	2736	1	5	3
Hydro-electric	Impounded – Mountain Chute	520 000	Not Estimated	10	-	5.5
	Impounded – Péribonka	21 000	Not Estimated	1	-	
	Pumped Storage	21 000 – 520 000	Not Estimated	1-10	-	5.5
	Diversion	0	0	0	0	0
Renewable	Wind	0	0	0	0	0
	Photovoltaic	0	0	0	0	0
OMI Project	Transmission line	0	0	0	0	0
	Hydroelectric Generation	21 000 – 520 000	Not Estimated	1-10	-	5.5
	Total	21 000 – 520 000	Not Estimated	1-10	-	5.5

8.4 WASTE

From the values identified in section 7.4, it is now possible to assign a ranking from 0-10 of possible waste disposal/storage impact on the physical land use requirements. From the values found, it is clear that a number of generation options do not produce operational waste and therefore rank 0 on the scale. The relative ranking was developed by assigning the highest value (11.2 tonnes/MW for coal fired generation) a rank of 10 and all other ranks assigned equally between the remaining ranks using a rank separation of 1.23 tonnes/MW. All other values were provided with a relative ranking between 1 and 10. The results are presented in Table 8.35.

TABLE 8.35
RANK VALUES FOR OPERATIONAL WASTE

Operational Waste (tonnes/MW)	Rank
0	0
0.01 – 1.23	1
1.24 – 2.46	2
2.47 – 3.69	3
3.70 – 4.92	4
4.93 – 6.16	5
6.17 – 7.39	6
7.40 – 8.62	7
8.63 – 9.85	8
9.86 – 11.08	9
≥ 11.09	10

TABLE 8.36
FINAL RANKING OF WASTE BY GENERATION OPTION AND WASTE TYPE

Generation Option	Generation Type	Waste Type	Value (tonnes/MW)		Rank
Thermal	Natural Gas	None	0		0
	Synthetic Gas	None	0		0
	Coal	Ash and Gypsum (not recycled or sold)	11.2		10
	Biomass	Fly and bottom ash	0.11		1
Nuclear	CANDU	Low, Intermediate stored	0.32	0.52	1
	CANDU	Used fuel in storage	0.20		
Hydroelectric	Impounded, Pumped Storage or Diversion	None	0		0
Renewable	Wind	None	0		0
	Photovoltaic	None	0		0
OMI Project	Transmission line	None	0		0
	Hydroelectric	None	0		0
	Total	None	0		0

8.5 SUSTAINABILITY

From the values identified in section 7.5, specifically sub-section 7.5.5, it is now possible to assign a ranking from 1-10 of the possible sustainability of fuel sources. From the information presented, it is clear that the OMI Project, biomass fuel, wind and water represent the best electricity sources with respect to sustainability. However, given that freshwater already receives pressure from other uses, it should not be ranked as well as wind. Two categories of infinite supply were created, that which is currently un-utilized (rank of 0) and that which currently has some pressure already applied to the resource (rank of 1).

From these, the remaining ranks (2 through 10) are reserved for resources that are not finite but for which a ranking may be applied based on the estimated number of years of production available. SENES estimates that development and approval time for a new technology is approximately 25 years. Accordingly, the worst ranking (10) was applied to a finite resource with 0 to 24 years of production remaining. Ranking then proceeded in 25 year increments. Table 8.37 presents the rankings for sustainability.

TABLE 8.37
RANKING VALUES FOR SUSTAINABILITY

Criteria	Rank
Infinite supply	0
Infinite supply with constraints	1
Finite supply with greater than 225 years of production remaining.	2
Finite supply with 200 – 224 years of production remaining.	3
Finite supply with 175 – 199 years of production remaining.	4
Finite supply with 150 – 174 years of production remaining.	5
Finite supply with 125 – 149 years of production remaining.	6
Finite supply with 100 – 124 years of production remaining.	7
Finite supply with 50 – 99 years of production remaining.	8
Finite supply with 25 – 49 years of production remaining.	9
Finite supply with 0 – 24 years of production remaining.	10

Table 8.38 Presents the final ranking for sustainability for each generation option based on the supply of the fuel source.

TABLE 8.38
FINAL RANKING FOR SUSTAINABILITY FOR EACH GENERATION OPTION

Generation Option	Fuel	Renewability of Fuel	Estimated Years of Production Remaining	Rank	Final Generation Option Rank
Thermal	Natural Gas	Finite	70	8	8
	Coal	Finite	500	2	2
	Biomass	Infinite	N/A	1	1
Nuclear	Uranium	Finite	40	9	5.3
	Uranium	Finite	172	5	
	Uranium	Finite	250	2	
Hydroelectric	Water	Infinite	N/A	1	1
Renewable	Wind	Infinite	N/A	0	0
	Solar	Infinite	N/A	0	0
OMI Project	Land	Finite	5348	2	2
	Water	Infinite	N/A	1	1
	Total	N/A	N/A	2	2

9.0 SCORING SYSTEM

The final result from the overall process is a table that compares generating options by the key environmental criteria. There are three resulting tables that summarize the information presented in Chapters 7 and 8. Table 9.1 provides a comparison of generation options and the associated rankings from Chapter 8 for the three Air Impact criteria, Land Use, Water Use, Waste and Sustainability as well as a total ranking for each generation option/technology style. Table 9.2 provides the actual comparison values for each of the three Air Impact criteria and the associated rankings for each generation option/technology style. Table 9.3 provides the actual comparison values for Land Use, Water Use, Waste and Sustainability and the associated rankings for each generation option/technology style. Together these three tables provide the summary for analyses completed in this study.

9.1 EVALUATION OF THE GENERATION OPTIONS

In developing this methodology for evaluating the natural environment impacts from different generation options, SENES intended that the methods be easily applied to different supply option mixes and represent the best available information regarding generation impact. From Table 9.1 in this Chapter, the information can be used to evaluate different supply mix options by applying a percentage of the total power mix to the specific generation option. For example, for a supply mix with 20% natural gas, 5% coal, 45% nuclear and 30% hydroelectric the information in the table could be used as follows:

- Natural Gas total rank for combined cycle 50% efficient, dry low-NO_x and once-through cooling becomes 17.5 x 0.20 = 3.5
- Coal total rank for pulverized coal 50% efficient, dry low-NO_x with plus post burner control and once-through cooling becomes 37.5 x 0.05 = 1.88
- Nuclear total rank for pressurized water reactor and once-through cooling becomes 18.58 x 0.45 = 18.36
- Hydroelectric total rank for pumped storage with a concrete dam becomes 7.5 x 0.30 = 2.25

The supply mix rank becomes 3.5+1.88+18.36+2.25 = 26 providing a ranking that can be evaluated against other supply mix options for total expected impacts to the natural environment.

In a similar manner, Tables 9.2 and 9.3 can be used to calculate expected impacts of a supply mix. This may prove particularly important for summing the net expected greenhouse gases in order to compare potential impacts of different supply mixes, generation options or technologies within supply mixes/generation options.

9.1.1 Adaptability of this Methodology

The development of this methodology was intended to encompass either broad categories of generation options (for example all coal fired stations in land use) or specific and commonly utilized technologies that use the same fuel source but present different environmental impacts (for example coal fired station using pulverized coal with low-NO_x and post burner control). The former is particularly true for land impacts, water impacts, waste and sustainability. The latter is applicable primarily for air impacts.

The environmental criteria for which the evaluation was broadly applied to generation options – land impacts, water impacts, waste and sustainability – would be easily applied to new technologies because impacts are expected to be similar. For example, all natural gas stations with once-through cooling will have roughly a 76,000L/MWh impact on water and therefore a rank of about 1.5/10 regardless of whether they represent new or old technology. However, for air impacts, although the methodology will flow through for any new generation option, emissions rates will be specific to the new technology and therefore new rankings will likely need to be developed.

In this study, only one transmission line was evaluated, the OMI Project line that will provide a high voltage connection between Manitoba and Ontario. Caution must be exercised in using the numbers generated for this specific project to other transmission that may be considered. In this study, impacts from the transmission line on air, water and waste with respect to the natural environment were all zero. The scope of land impacts for a transmission line is dependant on the length of the line but, the amount of power that can be transmitted is not dependent on the length of the line. This means that the calculated value for land impacts will be skewed by the length of the transmission line. Consequently, the rank of land impacts will change based on the length of the line and using the value presented in this study will not be transferable to other transmission lines. This same argument could be made for the sustainability calculation made for the OMI Project in this study. In order to evaluate the impacts of other transmission lines, new data will need to be compiled that reflects impacts to land and sustainability. Evaluation of transmission lines for any generation option is a site specific feature comparable to access roads.

9.1.2 Environmental Criteria Weighting

For the present time, relative weightings between the environmental criteria have not been applied, they are all assumed to be equal. The relative importance of one aspect of the environment versus another is largely a measure of societal values and/or politics (e.g., commitment to meet Kyoto).

With respect to the air aspects of the environment and the relative importance of conventional air pollutants, GHGs and radiological emissions, we recommend looking to the experience of the European Union ExternE documents.

ExternE developed aggregated costs (mECU/kWh) based on the relative damage to human health and the environment from the life-cycle effects of different power options. The ExternE reports for France (Spadaro and Rabl, 1998) and the Netherlands (Dorland 1997) present the following aggregated costs:

	Aggregate Cost (mECU/kWh)	
	France	**Netherlands**
Conventional pollutants[1]	20	10
GHG[1]	30	20
Radioactivity	0.05	7

[1]Based on natural gas

The relatively higher aggregate cost for radioactivity in the Netherlands is due to their consideration of fuel reprocessing. The relative values are somewhat surprising, as at the time of the analysis, France did have a complete fuel cycle from mining through reprocessing. Canada does not reprocess fuel, but we recognize the perception issues associated with the nuclear industry. For the purposes of this study we recommend the following weighting values which are intermediate to those reported in the ExternE reports for France and the Netherlands:

- Conventional pollutants – 10
- GHG – 20
- Radioactivity – 1

This would be applied in the following fashion for the CANDU reactor:

- Conventional rank – 1 x 10 = 10
- Radioactivity rank – 6 x 1 = 6
- GHG rank – 1 x 20 = 20
- Total Rank = 36

Weightings may also be used, in part to develop rankings with a greater consideration of siting. For example, installation of fossil fuel generation equipment in the Greater Toronto Area, which already has a burdened air shed, may warrant a higher relative weighting to Health Air Impacts.

9.2 CUMULATIVE EFFECTS

According to the EA Practitioner's Guide, a Cumulative Effects Assessment (CEA) is:

> "…an assessment of those incremental effects of an action on the environment when the effects are combined with those from other past, existing and future actions"

To evaluate the potential difference between generation options, the cumulative effects assessment will, in essence, be the sum of the effects from the different Supply Option Mixes being considered. To simplify the evaluation, and since an evaluation of cumulative effects is basically site specific, it is assumed that the past and existing conditions for all alternatives are equal. Therefore, at this stage they are not specifically considered.

Rather, from a decision standpoint, an evaluation of the total effect from the different power mixes will provide a measure of the cumulative effect of each alternative.

TABLE 9.1
EVALUATION OF GENERATION OPTIONS AND TYPES BY THE KEY ENVIRONMENTAL CRITERIA RANKING

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
					1	**1**	**1**	**1**	**1.00**	**1**	**1.00**	
Thermal	Natural Gas	Combined Cycle 50% efficient	Once-through cooling	Steam injection	2	0	4	1	2.50	0	8.00	17.50
Thermal	Natural Gas	Combined Cycle 50% efficient	Once-through cooling	Dry-Low NOx	2	0	4	1	2.50	0	8.00	17.50
Thermal	Natural Gas	Combined Cycle 60% efficient	Once-through cooling	Steam injection	2	0	3	1	2.50	0	8.00	16.50
Thermal	Natural Gas	Combined Cycle 60% efficient	Once-through cooling	Dry-Low NOx	2	0	3	1	2.50	0	8.00	16.50
Thermal	Natural Gas	Cogeneration	Once-through cooling	Steam injection	2	0	3	1	2.50	0	8.00	16.50
Thermal	Natural Gas	Cogeneration	Once-through cooling	Dry-Low NOx	2	0	3	1	2.50	0	8.00	16.50
Thermal	Natural Gas	Combined Cycle 50% efficient	Cooling tower	Steam injection	2	0	4	1	1.50	0	8.00	16.50
Thermal	Natural Gas	Combined Cycle 50% efficient	Cooling tower	Dry-Low NOx	2	0	4	1	1.50	0	8.00	16.50
Thermal	Natural Gas	Combined Cycle 60% efficient	Cooling tower	Steam injection	2	0	3	1	1.50	0	8.00	15.50
Thermal	Natural Gas	Combined Cycle 60% efficient	Cooling tower	Dry-Low NOx	2	0	3	1	1.50	0	8.00	15.50
Thermal	Natural Gas	Cogeneration	Cooling tower	Steam injection	2	0	3	1	1.50	0	8.00	15.50
Thermal	Natural Gas	Cogeneration	Cooling tower	Dry-Low NOx	2	0	3	1	1.50	0	8.00	15.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Landfill Gas	Combined Cycle 50% efficient	Once-through cooling		3	0	0					3.00
Thermal	Landfill Gas	Combined Cycle 60% efficient	Once-through cooling		3	0	0					3.00
Thermal	Landfill Gas	Cogeneration	Once-through cooling		2	0	0					2.00
Thermal	Landfill Gas	Combined Cycle 50% efficient	Cooling tower		3	0	0					3.00
Thermal	Landfill Gas	Combined Cycle 60% efficient	Cooling tower		3	0	0					3.00
Thermal	Landfill Gas	Cogeneration	Cooling tower		2	0	0					2.00
Thermal	Digester Gas	Combined Cycle 50% efficient	Once-through cooling		3	0	2					5.00
Thermal	Digester Gas	Combined Cycle 60% efficient	Once-through cooling		2	0	2					4.00
Thermal	Digester Gas	Cogeneration	Once-through cooling		2	0	2					4.00
Thermal	Digester Gas	Combined Cycle 50% efficient	Cooling tower		3	0	2					5.00
Thermal	Digester Gas	Combined Cycle 60% efficient	Cooling tower		2	0	2					4.00
Thermal	Digester Gas	Cogeneration	Cooling tower		2	0	2					4.00
Thermal	Coal	Pulverized Coal (35% efficient)	Once-through cooling	Low-NOx	8	10	9	1	3.50	10	2.00	43.50
Thermal	Coal	Pulverized Coal (35% efficient)	Once-through cooling	Low-NOx and Post Burner Control	5	10	9	1	3.50	10	2.00	40.50
Thermal	Coal	Pulverized Coal (40% efficient)	Once-through cooling	Low-NOx	7	10	8	1	3.50	10	2.00	41.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Coal	Pulverized Coal (40% efficient)	Once-through cooling	Low-NOx and Post Burner Control	5	10	8	1	3.50	10	2.00	39.50
Thermal	Coal	Pulverized Coal (50% efficient)	Once-through cooling	Low-NOx	6	10	7	1	3.50	10	2.00	39.50
Thermal	Coal	Pulverized Coal (50% efficient)	Once-through cooling	Low-NOx and Post Burner Control	4	10	7	1	3.50	10	2.00	37.50
Thermal	Coal	Pulverized Coal (60% efficient)	Once-through cooling	Low-NOx	5	10	6	1	3.50	10	2.00	37.50
Thermal	Coal	Pulverized Coal (60% efficient)	Once-through cooling	Low-NOx and Post Burner Control	3	10	6	1	3.50	10	2.00	35.50
Thermal	Coal	Cyclone (35% efficient)	Once-through cooling	Low-NOx	10	10	9	1	3.50	10	2.00	45.50
Thermal	Coal	Cyclone (35% efficient)	Once-through cooling	Low-NOx and Post Burner Control	5	10	9	1	3.50	10	2.00	40.50
Thermal	Coal	Cyclone (40% efficient)	Once-through cooling	Low-NOx	9	10	8	1	3.50	10	2.00	43.50
Thermal	Coal	Cyclone (40% efficient)	Once-through cooling	Low-NOx and Post Burner Control	5	10	8	1	3.50	10	2.00	39.50
Thermal	Coal	Cyclone (50% efficient)	Once-through cooling	Low-NOx	7	10	7	1	3.50	10	2.00	40.50
Thermal	Coal	Cyclone (50% efficient)	Once-through cooling	Low-NOx and Post Burner Control	4	10	7	1	3.50	10	2.00	37.50
Thermal	Coal	Cyclone (60% efficient)	Once-through cooling	Low-NOx	6	10	6	1	3.50	10	2.00	38.50
Thermal	Coal	Cyclone (60% efficient)	Once-through cooling	Low-NOx and Post Burner Control	3	10	6	1	3.50	10	2.00	35.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Coal	Stoker (35% efficient)	Once-through cooling	Low-NOx	6	10	9	1	3.50	10	2.00	41.50
Thermal	Coal	Stoker (35% efficient)	Once-through cooling	Low-NOx and Post Burner Control	5	10	9	1	3.50	10	2.00	40.50
Thermal	Coal	Stoker (40% efficient)	Once-through cooling	Low-NOx	6	10	8	1	3.50	10	2.00	40.50
Thermal	Coal	Stoker (40% efficient)	Once-through cooling	Low-NOx and Post Burner Control	4	10	8	1	3.50	10	2.00	38.50
Thermal	Coal	Stoker (50% efficient)	Once-through cooling	Low-NOx	5	10	7	1	3.50	10	2.00	38.50
Thermal	Coal	Stoker (50% efficient)	Once-through cooling	Low-NOx and Post Burner Control	3	10	7	1	3.50	10	2.00	36.50
Thermal	Coal	Stoker (60% efficient)	Once-through cooling	Low-NOx	4	10	6	1	3.50	10	2.00	36.50
Thermal	Coal	Stoker (60% efficient)	Once-through cooling	Low-NOx and Post Burner Control	3	10	6	1	3.50	10	2.00	35.50
Thermal	Coal	Circulating Fluid Bed (35% efficient)	Once-through cooling	Low-NOx	3	10	10	1	3.50	10	2.00	39.50
Thermal	Coal	Circulating Fluid Bed (35% efficient)	Once-through cooling	Low-NOx and Post Burner Control	2	10	10	1	3.50	10	2.00	38.50
Thermal	Coal	Circulating Fluid Bed (40% efficient)	Once-through cooling	Low-NOx	2	10	9	1	3.50	10	2.00	37.50
Thermal	Coal	Circulating Fluid Bed (40% efficient)	Once-through cooling	Low-NOx and Post Burner Control	2	10	9	1	3.50	10	2.00	37.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Coal	Circulating Fluid Bed (50% efficient)	Once-through cooling	Low-NOx	2	10	8	1	3.50	10	2.00	36.50
Thermal	Coal	Circulating Fluid Bed (50% efficient)	Once-through cooling	Low-NOx and Post Burner Control	1	10	8	1	3.50	10	2.00	35.50
Thermal	Coal	Circulating Fluid Bed (60% efficient)	Once-through cooling	Low-NOx	2	10	7	1	3.50	10	2.00	35.50
Thermal	Coal	Circulating Fluid Bed (60% efficient)	Once-through cooling	Low-NOx and Post Burner Control	1	10	7	1	3.50	10	2.00	34.50
Thermal	Coal	Bubbling Fluid Bed (35% efficient)	Once-through cooling	Low-NOx	6	10	10	1	3.50	10	2.00	42.50
Thermal	Coal	Bubbling Fluid Bed (35% efficient)	Once-through cooling	Low-NOx and Post Burner Control	3	10	10	1	3.50	10	2.00	39.50
Thermal	Coal	Bubbling Fluid Bed (40% efficient)	Once-through cooling	Low-NOx	5	10	9	1	3.50	10	2.00	40.50
Thermal	Coal	Bubbling Fluid Bed (40% efficient)	Once-through cooling	Low-NOx and Post Burner Control	3	10	9	1	3.50	10	2.00	38.50
Thermal	Coal	Bubbling Fluid Bed (50% efficient)	Once-through cooling	Low-NOx	4	10	8	1	3.50	10	2.00	38.50
Thermal	Coal	Bubbling Fluid Bed (50% efficient)	Once-through cooling	Low-NOx and Post Burner Control	2	10	8	1	3.50	10	2.00	36.50
Thermal	Coal	Bubbling Fluid Bed (60% efficient)	Once-through cooling	Low-NOx	4	10	7	1	3.50	10	2.00	37.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Coal	Bubbling Fluid Bed (60% efficient)	Once-through cooling	Low-NOx and Post Burner Control	2	10	7	1	3.50	10	2.00	35.50
Thermal	Coal	Pulverized Coal (35% efficient)	Pond cooling or Cooling tower	Low-NOx	8	10	9	1	2.50	10	2.00	42.50
Thermal	Coal	Pulverized Coal (35% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	5	10	9	1	2.50	10	2.00	39.50
Thermal	Coal	Pulverized Coal (40% efficient)	Pond cooling or Cooling tower	Low-NOx	7	10	8	1	2.50	10	2.00	40.50
Thermal	Coal	Pulverized Coal (40% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	5	10	8	1	2.50	10	2.00	38.50
Thermal	Coal	Pulverized Coal (50% efficient)	Pond cooling or Cooling tower	Low-NOx	6	10	7	1	2.50	10	2.00	38.50
Thermal	Coal	Pulverized Coal (50% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	4	10	7	1	2.50	10	2.00	36.50
Thermal	Coal	Pulverized Coal (60% efficient)	Pond cooling or Cooling tower	Low-NOx	5	10	6	1	2.50	10	2.00	36.50
Thermal	Coal	Pulverized Coal (60% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	3	10	6	1	2.50	10	2.00	34.50
Thermal	Coal	Cyclone (35% efficient)	Pond cooling or Cooling tower	Low-NOx	10	10	9	1	2.50	10	2.00	44.50
Thermal	Coal	Cyclone (35% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	5	10	9	1	2.50	10	2.00	39.50
Thermal	Coal	Cyclone (40% efficient)	Pond cooling or Cooling tower	Low-NOx	9	10	8	1	2.50	10	2.00	42.50
Thermal	Coal	Cyclone (40% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	5	10	8	1	2.50	10	2.00	38.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Coal	Cyclone (50% efficient)	Pond cooling or Cooling tower	Low-NOx	7	10	7	1	2.50	10	2.00	39.50
Thermal	Coal	Cyclone (50% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	4	10	7	1	2.50	10	2.00	36.50
Thermal	Coal	Cyclone (60% efficient)	Pond cooling or Cooling tower	Low-NOx	6	10	6	1	2.50	10	2.00	37.50
Thermal	Coal	Cyclone (60% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	3	10	6	1	2.50	10	2.00	34.50
Thermal	Coal	Stoker (35% efficient)	Pond cooling or Cooling tower	Low-NOx	6	10	9	1	2.50	10	2.00	40.50
Thermal	Coal	Stoker (35% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	5	10	9	1	2.50	10	2.00	39.50
Thermal	Coal	Stoker (40% efficient)	Pond cooling or Cooling tower	Low-NOx	6	10	8	1	2.50	10	2.00	39.50
Thermal	Coal	Stoker (40% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	4	10	8	1	2.50	10	2.00	37.50
Thermal	Coal	Stoker (50% efficient)	Pond cooling or Cooling tower	Low-NOx	5	10	7	1	2.50	10	2.00	37.50
Thermal	Coal	Stoker (50% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	3	10	7	1	2.50	10	2.00	35.50
Thermal	Coal	Stoker (60% efficient)	Pond cooling or Cooling tower	Low-NOx	4	10	6	1	2.50	10	2.00	35.50
Thermal	Coal	Stoker (60% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	3	10	6	1	2.50	10	2.00	34.50
Thermal	Coal	Circulating Fluid Bed (35% efficient)	Pond cooling or Cooling tower	Low-NOx	3	10	10	1	2.50	10	2.00	38.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Coal	Circulating Fluid Bed (35% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	2	10	10	1	2.50	10	2.00	37.50
Thermal	Coal	Circulating Fluid Bed (40% efficient)	Pond cooling or Cooling tower	Low-NOx	2	10	9	1	2.50	10	2.00	36.50
Thermal	Coal	Circulating Fluid Bed (40% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	2	10	9	1	2.50	10	2.00	36.50
Thermal	Coal	Circulating Fluid Bed (50% efficient)	Pond cooling or Cooling tower	Low-NOx	2	10	8	1	2.50	10	2.00	35.50
Thermal	Coal	Circulating Fluid Bed (50% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	1	10	8	1	2.50	10	2.00	34.50
Thermal	Coal	Circulating Fluid Bed (60% efficient)	Pond cooling or Cooling tower	Low-NOx	2	10	7	1	2.50	10	2.00	34.50
Thermal	Coal	Circulating Fluid Bed (60% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	1	10	7	1	2.50	10	2.00	33.50
Thermal	Coal	Bubbling Fluid Bed (35% efficient)	Pond cooling or Cooling tower	Low-NOx	6	10	10	1	2.50	10	2.00	41.50
Thermal	Coal	Bubbling Fluid Bed (35% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	3	10	10	1	2.50	10	2.00	38.50
Thermal	Coal	Bubbling Fluid Bed (40% efficient)	Pond cooling or Cooling tower	Low-NOx	5	10	9	1	2.50	10	2.00	39.50
Thermal	Coal	Bubbling Fluid Bed (40% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	3	10	9	1	2.50	10	2.00	37.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Coal	Bubbling Fluid Bed (50% efficient)	Pond cooling or Cooling tower	Low-NOx	4	10	8	1	2.50	10	2.00	37.50
Thermal	Coal	Bubbling Fluid Bed (50% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	2	10	8	1	2.50	10	2.00	35.50
Thermal	Coal	Bubbling Fluid Bed (60% efficient)	Pond cooling or Cooling tower	Low-NOx	4	10	7	1	2.50	10	2.00	36.50
Thermal	Coal	Bubbling Fluid Bed (60% efficient)	Pond cooling or Cooling tower	Low-NOx and Post Burner Control	2	10	7	1	2.50	10	2.00	34.50
Thermal	Coal	IGCC	Once-through cooling	No CO2 removal	4	10	9	1	3.50	10	2.00	39.50
Thermal	Coal	IGCC	Once-through cooling	83% CO2 removal	4	10	4	1	3.50	10	2.00	34.50
Thermal	Coal	IGCC	Once-through cooling	90% CO2 removal	4	10	3	1	3.50	10	2.00	33.50
Thermal	Coal	IGCC	Pond cooling or Cooling tower	No CO2 removal	4	10	9	1	1.50	10	2.00	37.50
Thermal	Coal	IGCC	Pond cooling or Cooling tower	83% CO2 removal	4	10	4	1	1.50	10	2.00	32.50
Thermal	Coal	IGCC	Pond cooling or Cooling tower	90% CO2 removal	4	10	3	1	1.50	10	2.00	31.50
Thermal	Biomass	Combined with Coal	Once-through cooling	No Biomass Growth	2	0	10	1	3.50	1	1.00	18.50
Thermal	Biomass	Combined with Coal	Once-through cooling	With Biomass Growth	2	0	1	1	3.50	1	1.00	9.50
Thermal	Biomass	Gassification	Once-through cooling	No Biomass Growth	2	0	10	1	3.50	1	1.00	18.50
Thermal	Biomass	Gassification	Once-through cooling	With Biomass Growth	2	0	1	1	3.50	1	1.00	9.50
Thermal	Biomass	Combined with Coal	Pond cooling or Cooling tower	No Biomass Growth	2	0	10	1	2.50	1	1.00	17.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Thermal	Biomass	Combined with Coal	Pond cooling or Cooling tower	With Biomass Growth	2	0	1	1	2.50	1	1.00	8.50
Thermal	Biomass	Gassification	Pond cooling or Cooling tower	No Biomass Growth	2	0	10	1	2.50	1	1.00	17.50
Thermal	Biomass	Gassification	Pond cooling or Cooling tower	With Biomass Growth	2	0	1	1	2.50	1	1.00	8.50
Nuclear		CANDU Reactor (HWR)	Once-through cooling		1	6	1	1	4.25	1	5.33	19.58
Nuclear		Advanced CANDU (ACU - HWR)	Once-through cooling		1	6	1	1	4.25	1	5.33	19.58
Nuclear		Pressurized Water Reactor (PWR)	Once-through cooling		1	5	1	1	4.25	1	5.33	18.58
Nuclear		Boiling Water Reactor (BWR)	Once-through cooling		1	5	1	1	4.25	1	5.33	18.58
Nuclear		CANDU Reactor (HWR)	Pond cooling or Cooling tower		1	6	1	1	3.00	1	5.33	18.33
Nuclear		Advanced CANDU (ACU - HWR)	Pond cooling or Cooling tower		1	6	1	1	3.00	1	5.33	18.33
Nuclear		Pressurized Water Reactor (PWR)	Pond cooling or Cooling tower		1	5	1	1	3.00	1	5.33	17.33
Nuclear		Boiling Water Reactor (BWR)	Pond cooling or Cooling tower		1	5	1	1	3.00	1	5.33	17.33
Hydroelectric		Rock Filled Dam	Pumped Storage		0	0	0	0	5.50	0	1.00	6.50
Hydroelectric		Concrete Dam	Pumped Storage		0	0	1	0	5.50	0	1.00	7.50
Hydroelectric		Rock Filled Dam - Reservoir	Impoundment		0	0	1	4	5.50	0	1.00	11.50
Hydroelectric		Concrete Dam - Reservoir	Impoundment		0	0	1	4	5.50	0	1.00	11.50

Generation Option	Generation Type				Air Rankings			Land Use	Water Use	Waste	Sustainability	Total Rank
	Fuel Type	Technology	Cooling Water Style	Air Controls	Conventional Rank	Radioactivity Rank	GHG Rank					
Hydroelectric			Diversion		0	0	0	0	0.00	0	1.00	1.00
Wind					1	0	1	5	0.00	0	0.00	6.50
Photovoltaic					5	0	5	1	0.00	0	0.00	11.00
OMI Project	Transmission Line				0	0	0	5	0.00	0	2.00	7.00
	Hydro Generation				0	0	1	4	5.50	0	1.00	11.50
	Total				0	0	1	8.5	5.50	0	2.00	17.00

Note: Numbers are not included for Land Impacts, Water Impacts, Waste or Sustainability for landfill gas or digester gas. To some degree, these impacts could be estimated using numbers and ranks for other technologies or generation options but, this estimation has not been made in this study. Their inclusion allows for air impacts to be evaluated.

TABLE 9.2 AIR IMPACT VALUES AND RANKINGS BY GENERATION OPTION

Generation Option	Generation Type			Air Emission Summary			Air Rankings			
	Fuel Type	Technology	Air Controls	Normalized Conventional Emissions (kg/MWh)	Radioactivity (person Sv/GW a)	Global Warming Potential (Tonnes CO2-eq/MWh)	Conventional Rank	Radioactivity Rank	GHG Rank	Total Rank
							1	1	1	
Thermal	Natural Gas	Combined Cycle 50% efficient	Steam injection	0.8	0.03	0.35	2	0	4	6
Thermal	Natural Gas	Combined Cycle 50% efficient	Dry-Low NOx	0.7	0.03	0.35	2	0	4	6
Thermal	Natural Gas	Combined Cycle 60% efficient	Steam injection	0.7	0.03	0.29	2	0	3	5
Thermal	Natural Gas	Combined Cycle 60% efficient	Dry-Low NOx	0.6	0.03	0.29	2	0	3	5
Thermal	Natural Gas	Cogeneration	Steam injection	0.6	0.03	0.25	2	0	3	5
Thermal	Natural Gas	Cogeneration	Dry-Low NOx	0.5	0.03	0.25	2	0	3	5
Thermal	Landfill Gas	Combined Cycle 50% efficient		1.2	0.03	0.40	3	0	0	3
Thermal	Landfill Gas	Combined Cycle 60% efficient		1.0	0.03	0.33	3	0	0	3
Thermal	Landfill Gas	Cogeneration		0.9	0.03	0.28	2	0	0	2
Thermal	Digester Gas	Combined Cycle 50% efficient		1.0	0.03	0.22	3	0	2	5
Thermal	Digester Gas	Combined Cycle 60% efficient		0.8	0.03	0.18	2	0	2	4
Thermal	Digester Gas	Cogeneration		0.7	0.03	0.15	2	0	2	4
Thermal	Coal	Pulverized Coal (35% efficient)	Low-NOx	3.3	20.0	0.96	8	10	9	27

Generation Option	Generation Type			Air Emission Summary			Air Rankings			
	Fuel Type	Technology	Air Controls	Normalized Conventional Emissions (kg/MWh)	Radioactivity (person Sv/GW a)	Global Warming Potential (Tonnes CO2-eq/MWh)	Conventional Rank	Radioactivity Rank	GHG Rank	Total Rank
Thermal	Coal	Pulverized Coal (35% efficient)	Low-NOx and Post Burner Control	2.1	20.0	0.96	5	10	9	24
Thermal	Coal	Pulverized Coal (40% efficient)	Low-NOx	2.9	20.0	0.85	7	10	8	25
Thermal	Coal	Pulverized Coal (40% efficient)	Low-NOx and Post Burner Control	1.8	20.0	0.85	5	10	8	23
Thermal	Coal	Pulverized Coal (50% efficient)	Low-NOx	2.3	20.0	0.70	6	10	7	23
Thermal	Coal	Pulverized Coal (50% efficient)	Low-NOx and Post Burner Control	1.4	20.0	0.70	4	10	7	21
Thermal	Coal	Pulverized Coal (60% efficient)	Low-NOx	1.9	20.0	0.59	5	10	6	21
Thermal	Coal	Pulverized Coal (60% efficient)	Low-NOx and Post Burner Control	1.2	20.0	0.59	3	10	6	19
Thermal	Coal	Cyclone (35% efficient)	Low-NOx	4.4	20.0	0.96	10	10	9	29
Thermal	Coal	Cyclone (35% efficient)	Low-NOx and Post Burner Control	2.2	20.0	0.96	5	10	9	24
Thermal	Coal	Cyclone (40% efficient)	Low-NOx	3.8	20.0	0.85	9	10	8	27
Thermal	Coal	Cyclone (40% efficient)	Low-NOx and Post Burner Control	2.0	20.0	0.85	5	10	8	23
Thermal	Coal	Cyclone (50% efficient)	Low-NOx	3.1	20.0	0.70	7	10	7	24
Thermal	Coal	Cyclone (50% efficient)	Low-NOx and Post Burner Control	1.6	20.0	0.70	4	10	7	21

Generation Option	Generation Type			Air Emission Summary			Air Rankings			
	Fuel Type	Technology	Air Controls	Normalized Conventional Emissions (kg/MWh)	Radioactivity (person Sv/GW a)	Global Warming Potential (Tonnes CO2-eq/MWh)	Conventional Rank	Radioactivity Rank	GHG Rank	Total Rank
Thermal	Coal	Cyclone (60% efficient)	Low-NOx	2.6	20.0	0.59	6	10	6	22
Thermal	Coal	Cyclone (60% efficient)	Low-NOx and Post Burner Control	1.3	20.0	0.59	3	10	6	19
Thermal	Coal	Stoker (35% efficient)	Low-NOx	2.7	20.0	0.96	6	10	9	25
Thermal	Coal	Stoker (35% efficient)	Low-NOx and Post Burner Control	1.9	20.0	0.85	5	10	9	24
Thermal	Coal	Stoker (40% efficient)	Low-NOx	2.3	20.0	0.69	6	10	8	24
Thermal	Coal	Stoker (40% efficient)	Low-NOx and Post Burner Control	1.6	20.0	0.69	4	10	8	22
Thermal	Coal	Stoker (50% efficient)	Low-NOx	1.9	20.0	0.69	5	10	7	22
Thermal	Coal	Stoker (50% efficient)	Low-NOx and Post Burner Control	1.3	20.0	0.69	3	10	7	20
Thermal	Coal	Stoker (60% efficient)	Low-NOx	1.6	20.0	0.59	4	10	6	20
Thermal	Coal	Stoker (60% efficient)	Low-NOx and Post Burner Control	1.1	20.0	0.59	3	10	6	19
Thermal	Coal	Circulating Fluid Bed (35% efficient)	Low-NOx	1.0	20.0	1.14	3	10	10	23
Thermal	Coal	Circulating Fluid Bed (35% efficient)	Low-NOx and Post Burner Control	0.6	20.0	1.14	2	10	10	22
Thermal	Coal	Circulating Fluid Bed (40% efficient)	Low-NOx	0.9	20.0	1.00	2	10	9	21

Generation Option	Generation Type			Air Emission Summary			Air Rankings			
	Fuel Type	Technology	Air Controls	Normalized Conventional Emissions (kg/MWh)	Radioactivity (person Sv/GW a)	Global Warming Potential (Tonnes CO2-eq/MWh)	Conventional Rank	Radioactivity Rank	GHG Rank	Total Rank
Thermal	Coal	Circulating Fluid Bed (40% efficient)	Low-NOx and Post Burner Control	0.6	20.0	1.00	2	10	9	21
Thermal	Coal	Circulating Fluid Bed (50% efficient)	Low-NOx	0.7	20.0	0.82	2	10	8	20
Thermal	Coal	Circulating Fluid Bed (50% efficient)	Low-NOx and Post Burner Control	0.4	20.0	0.82	1	10	8	19
Thermal	Coal	Circulating Fluid Bed (60% efficient)	Low-NOx	0.6	20.0	0.70	2	10	7	19
Thermal	Coal	Circulating Fluid Bed (60% efficient)	Low-NOx and Post Burner Control	0.4	20.0	0.70	1	10	7	18
Thermal	Coal	Bubbling Fluid Bed (35% efficient)	Low-NOx	2.4	20.0	1.14	6	10	10	26
Thermal	Coal	Bubbling Fluid Bed (35% efficient)	Low-NOx and Post Burner Control	1.2	20.0	1.14	3	10	10	23
Thermal	Coal	Bubbling Fluid Bed (40% efficient)	Low-NOx	2.1	20.0	1.00	5	10	9	24
Thermal	Coal	Bubbling Fluid Bed (40% efficient)	Low-NOx and Post Burner Control	1.1	20.0	1.00	3	10	9	22
Thermal	Coal	Bubbling Fluid Bed (50% efficient)	Low-NOx	1.7	20.0	0.82	4	10	8	22
Thermal	Coal	Bubbling Fluid Bed (50% efficient)	Low-NOx and Post Burner Control	0.9	20.0	0.82	2	10	8	20
Thermal	Coal	Bubbling Fluid Bed (60% efficient)	Low-NOx	1.4	20.0	0.70	4	10	7	21

Generation Option	Generation Type			Air Emission Summary			Air Rankings			
	Fuel Type	Technology	Air Controls	Normalized Conventional Emissions (kg/MWh)	Radioactivity (person Sv/GW a)	Global Warming Potential (Tonnes CO2-eq/MWh)	Conventional Rank	Radioactivity Rank	GHG Rank	Total Rank
Thermal	Coal	Bubbling Fluid Bed (60% efficient)	Low-NOx and Post Burner Control	0.7	20.0	0.70	2	10	7	19
Thermal	IGCC		No CO2 removal	1.6	20.0	0.98	4	10	9	23
Thermal	IGCC		83% CO2 removal	1.6	20.0	0.36	4	10	4	18
Thermal	IGCC		90% CO2 removal	1.6	20.0	0.30	4	10	3	17
Thermal	Biomass	Combined with Coal	No Biomass Growth	0.5	0	1.10	2	0	10	12
Thermal	Biomass	Combined with Coal	With Biomass Growth	0.5	0	0.07	2	0	1	3
Thermal	Biomass	Gassification	No Biomass Growth	0.8	0	1.10	2	0	10	12
Thermal	Biomass	Gassification	With Biomass Growth	0.8	0	0.06	2	0	1	3
Nuclear		CANDU Reactor (HWR)		0.3	10.7	0.01	1	6	1	8
Nuclear		Advanced CANDU (ACU - HWR)		0.3	10.7	0.01	1	6	1	8
Nuclear		Pressurized Water Reactor (PWR)		0.3	8.4	0.01	1	5	1	7
Nuclear		Boiling Water Reactor (BWR)		0.4	9.0	0.01	1	5	1	7
Hydroelectric		Pumped Storage - Rock Filled Dam		0.1	0	0.00	0	0	0	0
Hydroelectric		Pumped Storage - Concrete Dam		0.1	0	0.02	0	0	1	1
Hydroelectric		Impoundment - Rock Filled Dam -		0.1	0	0.02	0	0	1	1

Generation Option	Generation Type			Air Emission Summary			Air Rankings			
	Fuel Type	Technology	Air Controls	Normalized Conventional Emissions (kg/MWh)	Radioactivity (person Sv/GW a)	Global Warming Potential (Tonnes CO2-eq/MWh)	Conventional Rank	Radioactivity Rank	GHG Rank	Total Rank
		Reservoir								
Hydroelectric		Impoundment - Concrete Dam - Reservoir		0.1	0	0.03	0	0	1	1
Hydroelectric		Diversion					0	0	0	0
Wind				0.2	0	0.01	1	0	1	2
Photovoltaic				1.9	0	0.53	5	0	5	10
OMI Project	Transmission Line			0	0	0	0	0	0	0
	Hydro Generation			0.1	0	0.03	0	0	1	1
	Total			0.1	0	0.03	0	0	1	1

TABLE 9.3 LAND IMPACT, WATER IMPACT, WASTE AND SUSTAINABILITY VALUES AND RANKINGS BY GENERATION OPTION

Generation Option	Generation Type		Value Summary					Rank Summary				
	Fuel Type	Cooling Water Style	Land Use km^2/MW	Water Use - Withdrawal L/MWh	Water Use - Consumption L/MWh	Waste tonnes/MW	Sustainability (I or years of production)	Land Use Rank	Water Use Rank	Waste Rank	Sustainability Rank	Total Rank
								1	**1.00**	**1**	**1.00**	
Thermal	Natural Gas	Once-through cooling	0.00014-0.00021	76000	380	0	70	1	1.5	0	8	10.5
Thermal	Natural Gas	Cooling tower	0.00014-0.00022	874	684	0	70	1	1.5	0	8	10.5
Thermal	Coal	Once-through cooling	0.0057	190000	1140	11.2	500	1	3.5	10	2	16.5
Thermal	Coal	Pond cooling or Cooling tower	0.0057	1444-2280	760-1824	11.2	500	1	2.5	10	2	15.5
Thermal	Biomass	Once-through cooling	0.0037-0.012	190000	1140	0.11	I	1	3.5	1	1	6.5
Thermal	Biomass	Pond cooling or Cooling tower	0.0037-0.013	1444-2280	760-1824	0.11	I	1	2.5	1	1	5.5
Nuclear		Once-through cooling	0.00043-0.0025	205000-228000	1520	0.52	154	1	4.25	1	5.3	11.55
Nuclear		Pond cooling or Cooling tower	0.00043-0.0026	4180	2736	0.52	154	1	3	1	5.3	10.3
Hydroelectric		Pumped Storage	0	21000-520000	-	0	I	0	5.5	0	1	6.5
Hydroelectric		Impoundment	0.057-0.13	21000-520001	-	0	I	4	5.5	0	1	10.5
Hydroelectric		Diversion	0	0	-	0	I	0	0	0	1	1
Wind			0.10-0.15	0	0	0	I	4.5	0	0	0	4.5
Photovoltaic			0.0013	0	0	0	I	1	0	0	0	1
OMI Project	Transmission Line		0.13	0	0	0	5348	5	0	0	2	7

Generation Option	Generation Type		Value Summary					Rank Summary				
	Fuel Type	**Cooling Water Style**	**Land Use km^2/MW**	**Water Use - Withdrawal L/MWh**	**Water Use - Consumption L/MWh**	**Waste tonnes/MW**	**Sustainability (I or years of production)**	**Land Use Rank**	**Water Use Rank**	**Waste Rank**	**Sustainability Rank**	**Total Rank**
	Hydro Generation		0.057-0.13	21000-520000	-	0	I	4	5.5	0	1	10.5
	Total		0.18-0.26	21000-520000	-	0	-	8.5	5.5	0	2	16

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APPENDIX A

ENVIRONMENT AND PROJECT PHASE INTERACTION

Environmental Component	**Regulatory Approval Required**	**Resource Use**	**Atmospheric Environment**				**Public**		**Geology and Hydrogeology**				**Hydrology and Surface Water**			**Aquatic Environment**							**Terrestrial Environment**						**Land Use**					**Waste Material Generation**	
Environmental Subcomponent		Renewable/Non-renewable	Air Quality	Noise	Microclimate	Potential for Cumulative Impacts	Public Health and Safety for Humans	Potential for Cumulative Impacts	Geology	Soil	Groundwater Quality, Quantity and Flow	Potential for Cumulative Impacts	Hydrology	Surface Water Quantity	Potential for Cumulative Impacts	Surface Water Quality	Sediment Quality and Quantity Including Shoreline	Aquatic Biota	Species at Risk	Protected Areas	Aquatic Habitat	Navigation	Potential for Cumulative Impacts	Vegetation Communities and Species	Species at Risk	Protected Areas	Wildlife Habitat	Wildlife Communities and Species	Potential for Cumulative Impacts	Land Use	Landscape and Visual Setting	Archaeological Sites	Traditional Land and Resource Use	Potential for Cumulative Impacts	Solid Waste	Aquatic Effluent
Resource Extraction																																			
Phase element																																			
Processing																																			
Phase element																																			
Transport																																			
Phase element																																			
Construction																																			
Phase element																																			
Operation																																			
Phase element																																			
Accidents & Malfunctions																																			
Phase element																																			
Decommissioning																																			
Phase element																																			

Opening the Dialogue on Electricity Supply Mix

Stakeholder Consultation Report

A Report to the Ontario Power Authority (OPA)
by Decision Partners

November 2005

DECISION
PARTNERS

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Opening the Dialogue on Electricity Supply Mix

A. Introduction to the Stakeholder Consultation Process

OPA recognizes that effective stakeholder consultation is critical to its ability to achieve its long term planning mission. Such consultation helps focus knowledge and diverse perspectives in ways that can build an in-depth, shared understanding of electricity related topics important to the Government of Ontario and Ontarians.

OPA asked Decision Partners (DP) to develop and manage an effective, inclusive stakeholder consultation process as a key element in the preparation of Advice to the Minister on the appropriate supply mix to meet anticipated demand in the Province. The purpose of the consultation process was to help OPA professionals better understand stakeholder interests and priorities with respect to various aspects of the supply mix challenge. In-depth understanding of the range of issues and underlying rationale of stakeholder and public judgment of the future supply mix for Ontario along with the degree to which stakeholders and others felt they had an opportunity to participate in the process in a meaningful way was critical to OPA.

Stakeholder Consultation Purpose

The primary purpose of the process was to identify stakeholder interests and priorities regarding the future energy mix for Ontario, including the risks, benefits, and tradeoffs of each of the fuel source options. Stakeholder judgment criteria were integrated with the technical assessments and modeling undertaken by other members of the OPA team.

Overview of the Approach

Dialogue-based approaches involving diverse groups of citizens and stakeholders have become the standard for addressing important policy issues in Canada and elsewhere, replacing the mere provision of "expert" information. The most successful approaches combine sound science and systematic uncertainty analysis with participatory deliberation by an appropriate representation of affected parties, policy makers and specialized or focused interests.

Decision Partners used its science-based, expert model/mental models-based approach[1] that has proven instrumental to the success of a broad range of public and private clients in Canada, the United States, and internationally who are faced with similar complex challenges.

The selection of research methods must be suited to the research task. For this initiative, the task was to discover and characterize in-depth people's thinking about an appropriate 15 to 20 year supply mix for Ontario, extending to 2015 – 2020.

Decision Partners conducted mental models research with key stakeholders, which is qualitative in nature, and used the research results to design an Internet-based poll capable of generating quantitative information about, as well as additional insights into, Ontarians' perspectives on the supply mix challenge. Polling and group methods (such as focus groups) alone, or in combination, were deemed to be unsuitable for the task due to important limitations in both methods.

[1] The use of mental modeling and confirmatory large-scale population surveys is covered in depth in *Risk Communication: A Mental Models Approach*, by M. Granger Morgan, Baruch Fischhoff, Ann Bostrom, and Cynthia J. Atman, published by Cambridge University Press, 2002.

The mental models research method involves in-depth, one-on-one interviews. The one-on-one situation helps to approximate the decision-making environment within which most people form their attitudes about a topic. The method allows free expression and encourages elaboration on topics in order to reveal individual perspectives in considerable depth. Interviewees can readily raise topics that most interest them, but which may be outside of specific questions. Because a full set of beliefs is elicited from each interviewee, structured analyses are possible. Analysts can identify what people believe and why they believe it.

In keeping with the mental models research method, Decision Partners first prepared an expert model summarizing expert knowledge of influences on the quality of supply mix advice to the Minister and influences on stakeholder judgments of the supply mix advice. The expert model served as the basis for design of the stakeholder and web survey protocols, and as the analytical framework for both.

The stakeholder consultation process comprised six elements, summarized below:

1. Develop OPA Stakeholder Consultation Guiding Principles

The first step in the process was to work with the OPA team to determine their values and priorities for stakeholder consultation. Following several discussions, the following principles were developed to guide the stakeholder consultation process for the supply mix and future OPA initiatives.

Stakeholder Consultation Purpose

The purpose of stakeholder consultation is to further the mission of OPA by helping focus knowledge and diverse perspectives in ways that can build an in-depth, shared understanding of electricity related topics important to the Government of Ontario and Ontarians. Information and advice received through stakeholder consultation is considered by OPA to be critical to the Authority's ability to provide well-informed recommendations to the Minister of Energy.

The insight OPA gains through consultation with a range of stakeholders and the resulting advice to the Minister must effectively balance the needs, interests, and priorities of Ontarians, whether they are commercial, industrial, institutional, or residential electricity users.

Purpose of the Guiding Principles

The stakeholder consultation guiding principles have been developed to guide the design and implementation of OPA's stakeholder consultation processes and key activities. They also serve as guides for the conduct of OPA sponsors of consultation processes and the key participants in them.

Guiding Principles

OPA's stakeholder consultation efforts are focused on gaining insight and input required to inform mid- to long-term energy-related decisions. Consultation efforts are:

- Advisory in nature.
- Transparent.
- Inclusive.
- Stakeholders and all others are treated with respect and relevance.
- OPA offers multiple communication channels to enable stakeholder dialogue and input.
- Our stakeholder consultation processes call for clear, measurable objectives and evaluation of both the process and the outcomes.

2. Develop the Expert Model

The mental models research method calls for first integrating the knowledge of experts on the topic(s) at hand into a tractable form. For this purpose, Decision Partners prepared an expert model based on input from in-depth interviews with experts within OPA.

The resulting expert model is an influence diagram that captures and synthesizes expert knowledge of influences on the quality of supply mix advice to the Minister and influences on stakeholder judgments of the supply mix advice. While providing a valuable summary of expert knowledge, it also provides the analytical framework for the mental models and web survey research conducted for this initiative. It was used to design protocols for the mental model interviews and the web survey.

3. Conduct Mental Models Research

DP conducted 62 confidential, one-on-one interviews by telephone with 27 Industry stakeholders and 35 Non-industry stakeholders based on a sample of approximately 200 provided by OPA. This sample size is typical of that used in the qualitative mental models research method recommended by Decision Partners.

The purpose of the interviews was to discover the primary influences on stakeholder judgment of Ontario's need for electricity and their idea of an appropriate balance of supply mix elements – namely, conservation and demand management (CDM), renewable sources, and advanced conventional sources.

Interviewees were asked to respond to a series of questions that were designed to allow for free expression, followed by specific ratings questions. In order to reveal in-depth, individual perspectives, Interviewees were encouraged to raise additional topics spontaneously and to elaborate on their thoughts. Interviews were tape recorded (with permission) to enable subsequent analysis as required.

The design of the protocol enabled Decision Partners' researchers to capture the detailed thoughts of the interviewees, then assess varying sets of beliefs and judgments about elements of the supply mix portfolio. By following this research with the Ontario-wide web survey, it was possible to understand and quantify how broadly these perspectives were shared by people across the province.

4. Conduct Parallel Web Survey

The results of the mental models research were then compared with results of a parallel web survey of 879 individuals developed by Decision Partners and administered by Decima Research. Web Survey Respondents comprised a representative sample of Ontario's general population.

The web survey included closed- and open-ended questions, and the interview protocol involved open-ended questions followed by rating questions. This complementary protocol design enabled Decision Partners to analyze the results of the web survey and the mental models interviews against the same set of parameters.

5. Conduct Stakeholder Workshop

Decision Partners designed and facilitated a workshop with stakeholders who had participated in the mental models portion of the consultation process. The purpose of the workshop, held November 3, 2005, was to share information and enable electricity Industry and Non-industry stakeholder engage in dialogue on values, tradeoffs and tough choices on key challenges related to the development of an appropriate supply mix. This additional insight was used as OPA prepared its advice to the Minister.

6. Report on Consultation Findings

This report identifies influences on Industry stakeholders, Non-industry stakeholders and Ontarians' judgments of key issues related to the need for electricity, the most important impacts to consider, and a balanced supply mix portfolio. It discusses key findings from the consultation process, which was used by OPA to inform its advice to the Minister on supply mix options.

The consultation process includes the formal research conducted by Decision Partners: mental models research, web survey of a representative Ontario public and the stakeholder workshop. Other consultation channels – such as meetings, technical briefings with industry experts, position papers, etc. – were also used by OPA to generate input into the supply mix advice and are reported elsewhere in the OPA report.

Notes on the Research Component of the Report

The research segment compares findings and highlights important gaps and alignments between the various groups consulted: Industry stakeholders, Non-industry stakeholders, and web Survey Respondents (the Ontario Public). To aid the reader, mental models research and web survey research highlights are reported together.

Findings from the research are analyzed and reported against the expert models. For the purposes of this report, the mental models research instrument is referred to as the "mental models interview" or "interview." The web survey research instrument is referred to as the "web survey" or "survey." The aggregate mental models research sample is referred to as Interviewees, indicating all 62 Interviewees unless otherwise specified. The terms Industry and Non-industry refer to the 27 Industry stakeholders and 35 Non-industry stakeholders respectively; while the terms Respondents and Survey Respondents refer to the web-based survey sample of 879 Ontarians unless otherwise specified. Differences among these groups are noted where significant. Note that, when used, the terms "the majority" refers to > 80% of Interviewees or Respondents; "most" refers to 60-80% of Interviewees or Respondents; "many" is 40-60%, "some" is 20-40%, and "(a) few" is < 20%.

B. Mental Models and Web Survey Research

1. Mental Models Research Method

Research Sample

A "mental models" approach was used by Decision Partners to design conversational protocols for interviews with 62 stakeholders in two groups: 27 Industry and 35 Non-industry stakeholders. The research sample was provided by OPA. The Industry group included representatives of organizations such as utility companies, industry associations, electricity consultants, and labour associations. The Non-industry group included representatives of organizations such as municipalities, environmental non-government organizations, large electricity users, and individuals.

Pre-arranged interviews were conducted between September 15 and October 12, 2005. They ranged in duration from 20 to 105 minutes, with an average of 50 minutes.

Research Topics

Interviewees were offered an agenda of topics to discuss in a way that allowed for free expression. They were encouraged to raise spontaneously any additional topics and to elaborate on their perspectives on these topics.

The mental models protocol (or questionnaire), the outline of which is presented in the appendix, focused on the following topics:

- Influences on the Need for Electricity in Ontario
- Balance of Supply Mix Portfolio
- Influences on the Quality of Supply Mix Analysis
- Stakeholders' Advice to OPA

Other topics spontaneously mentioned included the following:

- The urgent societal need for electricity, including the impacts of the August 2003 blackout;
- Environmental policies, including issues related to the Federal Government's Kyoto commitments and the Ontario Government's coal phase-out policy;
- Timeframe considerations, including the immediate electricity needs, impacts of our choices on future generations, and the need to look beyond 15-20 years when it comes to electricity systems planning;
- The need for expert input – public input and stakeholder engagement into the supply mix advice in particular and the energy policy in general;
- Issues related to OPA and government leadership.

2. Web Survey Research Method

A parallel web survey of a representative sample of Ontarians was conducted based on the mental models research. The survey protocol designed by Decision Partners was based on key questions in the mental models interviews. Decima oversaw the data collection process; Decision Partners analyzed and reported the results.

The web survey of Ontario residents was conducted between October 3 and October 6, 2005. A total of 879 surveys were completed (target was 800). 53% of the respondents were male, while 47% were female. Respondents were asked about their familiarity with electricity issues in Ontario: 12% reported being very familiar, 68% were somewhat familiar, 18% were not very familiar, and 2% were not at all familiar. All data were also cross-tabulated to account for variations in Respondents' demographics and their judgments. Decision Partners analyzed the web survey results and compared them to the results of the mental models interviews for inclusion in this report. The margin of error on survey responses is +/- 3.3%, meaning that the true response is within 3.3 percentage points of the reported survey response 95% of the time.

The web survey protocol focused on the following topics:

- Influences on the Need for Electricity in Ontario
- Balance of Supply Mix Elements
- Ontarians' Advice to OPA
- Trusted Information Sources about Electricity Issues in Ontario

3. Overall Research Findings

The mental model and web survey research demonstrated clear priorities on the part of stakeholders and diversity in their beliefs about the importance of the supply mix elements, conservation and demand management, renewables, and advanced conventional sources. Top line findings are summarized in the following box:

Top-Line Research Findings

Priorities Regarding the Need for Electricity

- In general and on average, Industry and Non-industry stakeholders' judgments were very similar.
- The values and priorities underlying Interviewees' perceptions of the need for electricity in Ontario that influence their considerations on supply mix were remarkably consistent.
  - Availability and reliability were the primary influences on the need for electricity, ranked high by over 90% of all of the Industry and Non-industry Interviewees.
  - Environmental responsibility was next in terms of rated questions. It was rated high or medium by almost all of the Interviewees.
    - Several talked about health impacts of power generation when they discussed environmental responsibility.
  - But throughout the interview, Interviewees spoke more about availability of electricity and the economic impacts than they did environmental impacts – emphasizing that availability is "critical" and must be the priority.
- For the most part, Survey Respondents' judgments were similar:
  - When combined, availability and reliability of electricity were rated the most important factor by 52% of Respondents.
  - 17% of Respondents rated environmental responsibility as the most important factor.

Considerations on the Supply Mix Portfolio

- There is no one right portfolio:
  - The majority of Interviewees acknowledged the challenge of defining the ideal or even an optimal supply mix portfolio. As one noted, "there is no silver bullet." There is not one dominant portfolio among those proposed.
  - Survey Respondents did not have one preferred supply mix portfolio, nor was there a clear set of portfolio scenarios.
- A wide range of portfolios were offered. In general:
  - Industry Interviewees tended to favour conventional/ advanced conventional sources more than Non-industry Interviewees.
  - Non-industry Interviewees tended to favour a more balanced portfolio, though many Interviewees in both cohorts talked about the importance of "a balanced portfolio."
  - Survey Respondents favoured more renewables.
- In aggregate, Interviewees and Survey Respondents allocated about 20% to CDM, 30% to Renewables and 50% to Conventional or Advanced Conventional Technologies.

Considerations on Sources

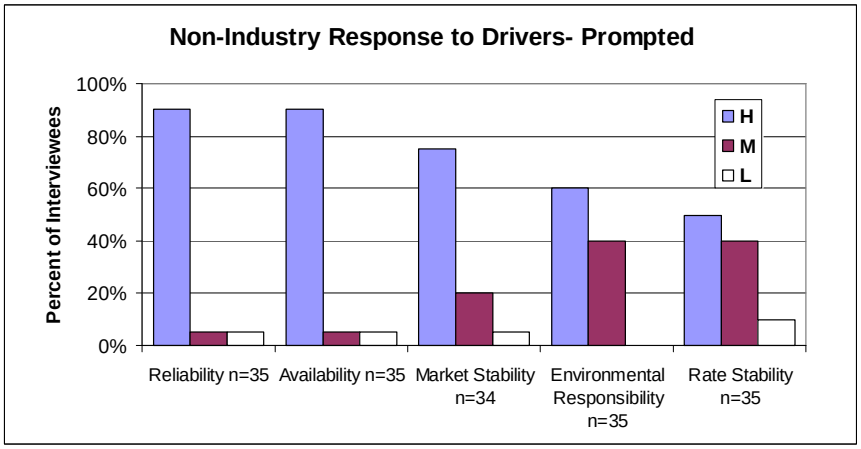
- Interviewees and Survey Respondents included a significant amount of wind in the Renewables portion of their portfolios; Survey Respondents and Non-Industry interviewees also favoured solar. Biomass was included in fairly significant amounts by Industry and Survey Respondents.
- Interviewees emphasized that the portfolio must be diverse in terms of cost of the various components (capital cost, fuel cost, maintenance cost), generation size and type, and environmental impact.
  - 55% Industry and 35% Non-industry believed it should include "clean coal"; 10% Industry and 25% Non-industry said it should not include coal.
  - 85% Industry and 50% Non-industry believed that nuclear should be part of the supply mix; 10% Industry and 15% Non-industry said it should not.
- Survey Respondents similarly emphasized diversity, but put greater emphasis on large-scale hydro, distributed generation and natural gas than the Interviewees.
  - 75% said the portfolio should include nuclear; 15% said it should not.
  - 70% said it should include coal; 18% said it should not.

Influences on the Need for Electricity in Ontario

Priorities underlying Interviewees' thoughts on design of the supply mix portfolio were clear and consistent: availability and reliability were the primary influences on the need for electricity, ranked high by over 90% of all of the Industry and Non-industry Interviewees. Environmental responsibility was next in terms of rated questions. It was rated high or medium by almost all of the Interviewees. But throughout the interview, Interviewees spoke more about availability of electricity and the economic impacts than they did environmental impacts – emphasizing that availability is "critical" and must be the priority.

While most Interviewees rated most influences high, there were some exceptions:

- Many said that rate stability was of medium or low importance because Ontarians should "experience the true price of electricity."
- Many distinguished between rate stability (price volatility) and price.
- A few (10% Non-industry) rated environmental impacts as highest in importance, noting the long-term impact of Ontarians' reliance on conventional sources.
- A few stated that availability and reliability were of medium or low importance, suggesting that Ontarians' were over-reliant on electricity.
- Most Interviewees acknowledged that tradeoffs were necessary because efforts to improve one factor often come at the expense of another.



Survey Respondents were asked to rate the importance of a series of factors related to electricity. For the most part, Survey Respondents' judgments were similar to those of the Interviewees.

Each factor was rated of high importance by over 50% of Survey Respondents. Availability and reliability of electricity was rated the most important factor by 52% of Respondents. 17% of Respondents rated environmental responsibility as the most important factor. The graph at the right summarizes these results.

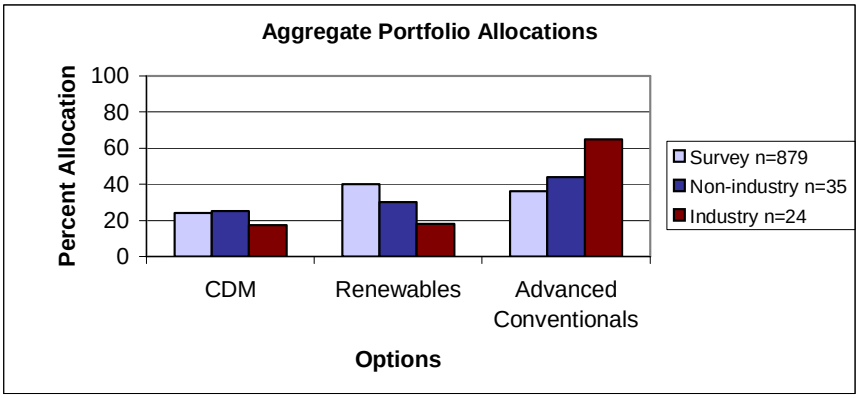
Percent of Survey Respondents Rating Most Important Factor	
Availability	**28**
Reliability	**24**
Stable Rates	**23**
Environmental Responsibility	**17**
Market Stability	**8**

Ontario Balance of Supply Mix Elements

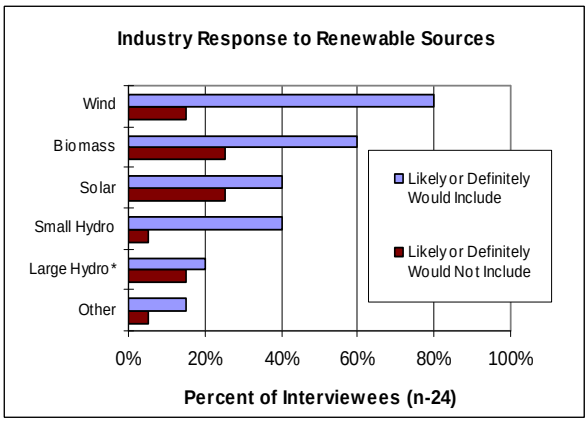
Interviewees were asked to suggest a supply mix portfolio by assigning percentages to each of three categories: conservation and demand management (CDM), renewable energy sources, and conventional and advanced technology conventional sources.

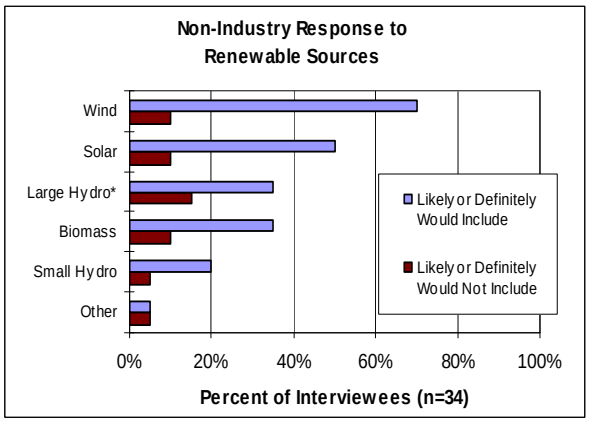
The majority of Interviewees acknowledged the challenge of defining the ideal or even an optimal supply mix portfolio. As one noted, "there is no silver bullet." Overall, both Industry and Non-industry portfolios ranged across the entire spectrum of possibilities. No single portfolio assignment emerged as the right one, nor was any portfolio dominant over the others. Industry Interviewees, however, tended to place greater emphasis on Conventional sources (65% on average) with support for CDM and Renewables being evenly split. Non-industry Interviewees tended to favour a more balanced portfolio, though many Interviewees in both groups talked about the importance of "a balanced portfolio." It is important to note that, by "balanced," they did not mean an even distribution, or one-third, one-third, one-third. Rather, they meant good proportional relationships among the three components: in aggregate, about 20% CDM, 30% renewables, and 50% advanced conventional.

Survey Respondents were also asked to suggest a supply mix portfolio by assigning percentages to each of three categories. Similar to findings in the mental models research, portfolio allocations varied widely across the entire range of possible portfolio allocations. On average, Survey Respondents allocated an amount for CDM similar to that of the Non-Industry Interviewees (24%). On average, Survey Respondents were more optimistic in their allocations of renewables (40%) and reacted less favourably to advanced conventional sources (34%) than both Industry and Non-industry interviewees. But it is worth noting that Respondents who rated environmental responsibility as the most important factor allocated significantly more of their portfolio to renewables and significantly less of their portfolio to advanced conventionals than those who rated availability as the most important.



Interviewees and Survey Respondents were also asked to determine whether they would include specific renewable sources in their supply mix portfolio. As illustrated by the graphs below, wind stood out as the clear winner for both groups. Judgments were mixed about solar, small hydro-electric, and biomass. Although not included in the specified definition for renewables, many interviewees spontaneously included large hydroelectric operations as renewable sources.

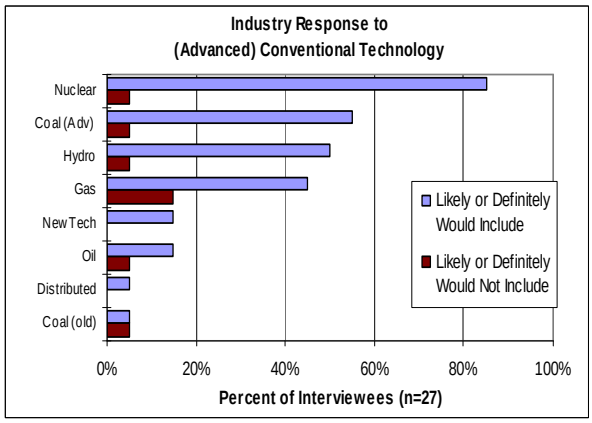


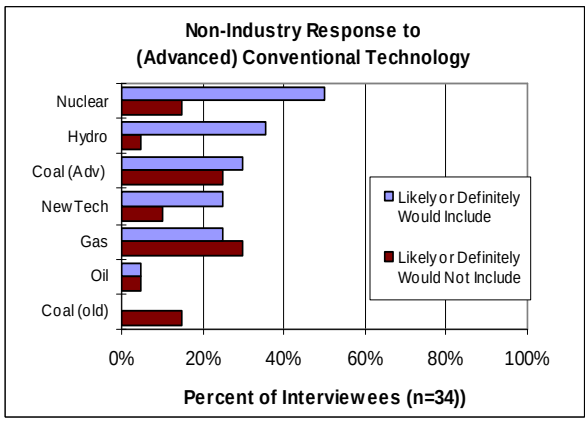


Among conventional sources, nuclear stood out as the most favourable source by both Industry and Non-industry groups. Advanced conventional coal and large hydro projects were also rated favourably. Oil and gas were seen to be less favourable due to issues of cost and availability. Interviewees emphasized that the portfolio must be diverse in terms of cost of the various components (capital cost, fuel cost, maintenance cost), generation size and type, and environmental impact.

Coal, about which Interviewees were not specifically asked, played a major role in many portfolios, as did nuclear:

- 55% Industry and 35% Non-industry believed the supply mix should include “clean coal.”
- 10% Industry and 25% Non-industry said it should not include coal.
- 85% Industry and 50% Non-industry believed that nuclear should be part of the supply mix.
- 10% Industry and 15% Non-industry said it should not.

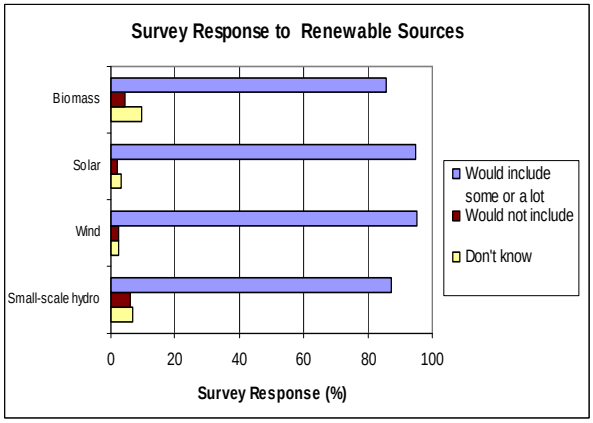


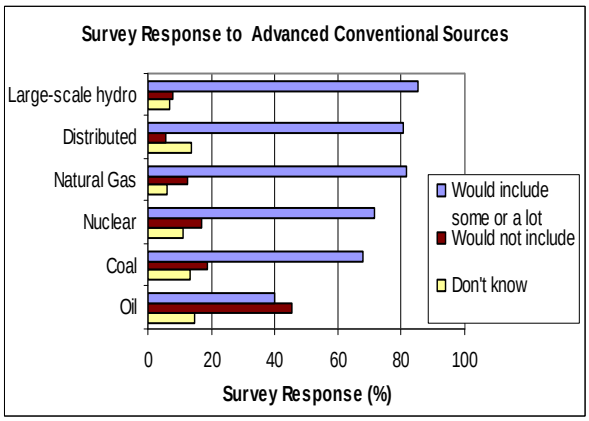


Interviewees were then asked to discuss the strengths and drawbacks of their portfolios. The most common benefit cited by both Industry and Non-industry Interviewees was the prospect of ensuring an available, reliable or sustainable supply of electricity. Environmental benefits were also frequently mentioned. The most commonly cited drawback mentioned was the difficulty of implementing the proposed portfolio. This drawback was commonly cited by Interviewees who had allocated a significant proportion of their portfolio to CDM.

Survey Respondents were also presented with a series of specific renewable and advanced conventional supply mix options and asked whether they would include these sources in their supply mix portfolios. The majority of respondents would include at least some of every renewable source. Except for oil,

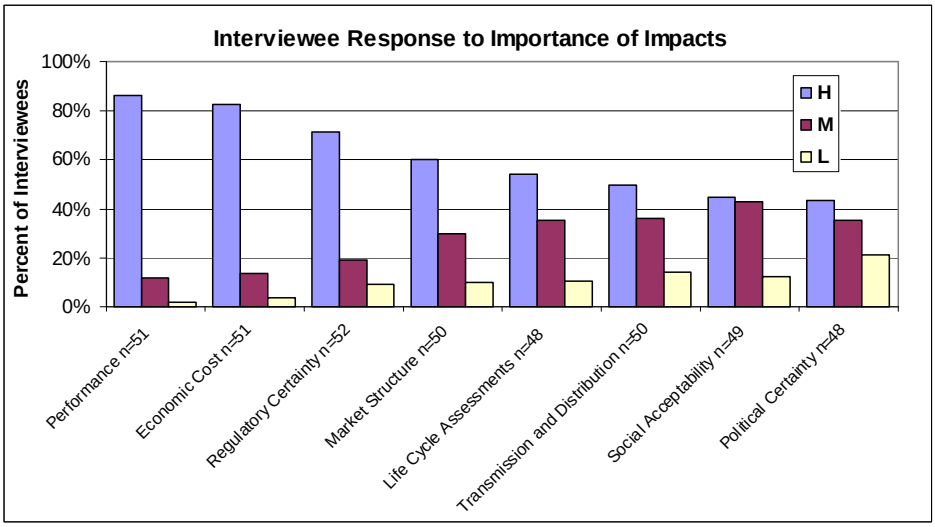
Respondents responded favorably to each of the advanced conventional sources, with large scale hydro the most favoured.





Influences on Supply Mix Elements

Interviewees were asked to rate the importance of the following impacts to OPA's supply mix assessment: performance, economic cost, market structure, impacts of transmission and distribution, regulatory certainty, political certainty, life-cycle assessments, and social acceptability. Again, Industry and Non-industry responses were very similar. On average, all Interviewees rated performance (capacity and efficiency of electricity generation), followed by cost (of producing and distributing electricity) and regulatory certainty as the most important impacts to consider. On average, Interviewees rated social acceptability as a less important factor. The following chart summarizes the aggregate (Industry and Non-industry) response to these questions:



Ontarians' Advice to OPA

At the close of the interview, when asked what one piece of advice they would give OPA as it moves forward in preparing advice to the Minister on the supply mix, Interviewees offered suggestions on the following (in order of mention):

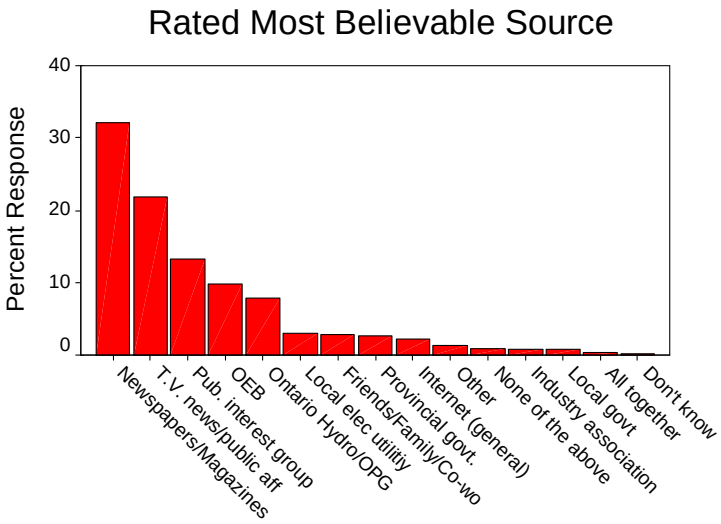
- The need for considered and decisive leadership by OPA.

- The need for a balanced approach.
- The need to demonstrate concern for the environment.
- The need to let the market prevail in decision-making.
- The need for public/stakeholder input.
- The need for expert input.
- The need to consider coal/nuclear options.

When Survey Respondents were given an opportunity to provide one piece of advice to OPA, 88% responded. Their open-ended responses varied widely. Environmental considerations, including the use of renewables, was mentioned most frequently (20% of Respondents). The most-cited broad categories of advice included: comments about the environment, the need for innovation, the need for public involvement, the cost of electricity, and the need for diversity in supply mix options.

Trusted Information Sources about Electricity Issues in Ontario

Survey Respondents were asked about the sources they rely on for information about electricity issues in Ontario. Most Respondents said that they rely on news media (television media, magazine and newspaper; over 60% responded "yes" in each category) and that they would not rely on "official" sources, including OEB, OPG and the government, or other people (over 60% responded "no" in each of these categories). When asked to choose the single most believable source, over 55% of Respondents chose media; "official" sources were much less favoured.



C. Stakeholder Workshop Highlights

OPA invited stakeholders who participated in the mental models interviews to attend a workshop, designed and facilitated by Decision Partners and held in Toronto on November 3, 2005. Almost 40 of the 62 Interviewees participated.

1. Workshop Purpose

The purpose of the workshop was to share information and to engage Industry and Non-industry stakeholders in dialogue on values, tradeoffs and tough choices on key challenges. The insight gained at the workshop was used to inform OPA's advice to the Minister of Energy on supply mix.

2. Key Activities

The workshop design and facilitation enabled open, frank discussion on the issues and challenges that mattered most to Participants. Four small breakout groups were formed to reflect the different backgrounds, interests, and perspectives on electricity issues among Industry and Non-industry stakeholders. Workshop activities (in order of the agenda) included the following:

- Sharing with workshop participants:
    - Highlights from the one-on-one research conducted by Decision Partners on the need for electricity in Ontario and consideration of the balance of supply mix elements;
    - Findings from the parallel web survey conducted by Decima Research;
- Using the research findings as a basis for dialogue to gain insight from participants in the first breakout session on:
    - The primary goal and key values regarding electricity supply in Ontario;
    - The criteria stakeholders will use to judge the elements of an appropriate supply mix portfolio for 2020;
- Framing the challenge: Amir Shalaby of OPA discussed the challenge of building an appropriate supply mix portfolio for 2015-2020;
- In the second breakout session two of the groups discussed specific challenges related to long term planning of the supply mix, first in the short term, 2005-2015, then in the longer term, 2015-2025;
- The other two groups identified and shared their views on the challenges regarding effective public policies within and between all levels of government, the benefits, the impediments or barriers, and the opportunities to facilitate. In addition, the groups addressed the interaction between public policies and private interests.
- Each of the groups presented the highlights of their discussion at the plenary session at the end of the workshop. Each group selected a spokesperson who presented the highlights from his or her groups' discussion. At the close of the Workshop, Amir Shalaby and Mary Ellen Richardson thanked the Participants for their thoughtful discussions and discussed how the results of stakeholder consultation process would value the Supply Mix advice.

3. Top-line Workshop Highlights

Participants used the insight from the research – along with the brief overview of the supply mix challenge by Mary Ellen Richardson and Amir Shalaby of OPA – as the basis for dialogue in the breakout sessions. The result was very rich dialogue by all of the breakout groups.

A primary observation is that the discussion in all groups focused on similar key issues. These broad issues emerged regardless of the specific questions that were posed for discussion in the breakout, suggesting that they were important issues to Participants:

- Stakeholder values regarding electricity in Ontario and the criteria for evaluating elements of the supply mix advice;
- The ability of the public to understand the challenges of the supply mix advice and the need to fill their information gaps;
- The challenges of supply mix planning and electricity planning more broadly;
- Public policy challenges, including the integral inter-ministerial relationships and relationships between the levels of government, and their impact on electricity planning and implementation;
- Specific public challenges of public versus private interests, including NIMBY; and
- Considerations on the role of OPA and Participants' advice to the Minister.

4. Breakout Group Discussion Highlights – Session One

The following highlights from Session One reflect statements made by individual Participants during discussions. Unless specified, statements should not be interpreted as consensus among the Participants.

In the Session One, groups were led through a broad discussion and asked for comments and observations on the following:

- The primary goal and key values regarding electricity supply in Ontario.

- The criteria stakeholders will use to judge the elements of an appropriate supply mix portfolio for 2020 – 2025.

Participants were initially asked for their general observations on the research. For example:

1. *What are your first thoughts on values and criteria, based on what you saw in the research?*
2. *What did the research confirm for you regarding stakeholder values and criteria? Any surprises?*
3. *Discuss/review the list below from the research. Thinking about values and criteria stakeholders will use to judge the elements of an appropriate supply mix, is anything missing?*

Criteria and Values

In general, Participants accepted the research results regarding the key goals and priorities of stakeholders, which showed that availability/reliability/sustainability of electricity was the most important priority, followed by environmental responsibility and then cost. For the most part, the groups confirmed these values. There were some notable differences among stakeholders' goals and priorities. Key discussion points:

- Participants in all groups tended to reinforce the research findings, commenting that the availability and reliability of electricity should be the most important drivers of OPA's mandate.
- Some Participants broadened the issue of electricity needs to energy needs. They stressed the importance of considering "integrated resource planning" that incorporates such options as district heating and cooling and combined heat and power.
- Most Participants, echoing the mental models and web survey research, concluded that in the end, the Ontario economy must be the most important priority – the economy is the primary driver of all decisions in the Province.
    - Participants in one group commented that the Government has not focused enough on the economic drivers for the Province.
- Some noted that the term "sustainability" is a broader issue than availability and reliability of electricity, incorporating environmental responsibility as well.
- Participants expressed surprise at the importance Survey Respondents (the Ontario Public) placed on availability and reliability of electricity, stating that their responses were more pragmatic than expected. There was some discussion that these ratings were likely confounded by citizens' private interests – such as NIMBY – and concerns about significant increases in the cost of electricity. (See also below, *Discussion Regarding an Informed Public*.)
- A similar topic raised was the how to consider the integral relationship between the following criteria: price, price volatility, environmental implications, capacity, location, etc., when evaluating supply mix options. Participants wondered if stakeholders, the public and the Governments' values were sensitive to the tradeoffs involved in the selection of an appropriate supply mix. More broadly, they wondered what is society willing to do, what is it willing to tolerate when it comes to ensuring the availability of electricity.
- When asked if there were additional values and criteria stakeholders will use to judge the elements of an appropriate supply mix that were not raised in the research, Participants suggested the following:
    - Competitiveness, since "we don't want Ontario to shut down."
    - The role of market focus vs. social mandate – how to value the tradeoffs between letting the market decide the supply mix and forcing supply options on the market.
    - The question of who should bear the risk of investments, for example, the risk of localized generation. It was noted by two groups that the private sector should take the risk rather than the public.
    - Risk management should be considered over the long-term: prudence, flexibility and ability to off-ramp if necessary in the longer run.
    - Some groups thought that the cost of electricity was marginalized in terms of priority. One Participant felt that, by neglecting cost (by default, allowing it to rise), an "energy-poverty" class of people who cannot afford electricity may emerge. Regarding Ontario's competitiveness in the market, another Participant suggested, "It's power at competitive

cost, not power at any cost." Others, however, argued that the lowest cost was not necessarily the primary concern.

- Some Participants suggested that the majority view held by Industry (placing a higher emphasis on advanced conventional sources than on renewables) does not reflect the priorities of the public entirely. Some stressed the importance of recognizing the high value that Survey Respondents placed on renewables.
- Some Participants thought that OPA's estimate of 1% annual growth in energy demand was too conservative.
- All groups discussed the feasibility of CDM goals.
- Participants in all groups commented on the challenges of implementing the current plans to replace phased-out coal. Participants noted the positive response to coal in the Mental Models and Web Survey research and said they hoped that these results would be carefully considered by OPA and the Minister. Participants recognized that the option to include advanced coal in the supply mix in the future likely requires continued investment in the current coal facilities.

An Informed Public and an "Energy-literate" Culture

One of the key themes that emerged from workshop was the value of the public's exposure to information and the need for an "energy-literate" culture. Many of the comments raised in the first breakout session, were underscored in the subsequent sessions and the plenary at the end of the day. Key areas of discussion included the following:

- There was noted surprise at the consistency of Survey Respondents and the degree to which their judgments and beliefs reflected those of Industry and Non-industry stakeholders. Participants interpreted this to mean that Survey Respondents were fairly well informed on electricity related challenges.
- Participants noted the difference between the ability of the public to understand the issues around electricity – "people are a lot smarter than we give them credit for being" – and the information they receive about these issues. Although it was noted that the public appeared to be more informed than was initially believed, all groups felt that information gaps would remain, specifically regarding the cost of renewables sources and the overall cost of electricity.
- Participants in each group attributed the predicted information gaps to the lack of balanced and factual information reaching the public.
- Participants thought that citizens need to know the "true cost of electricity." Some suggested that citizens need to understand the complexity of making energy available – "making energy happen" – in order to gain an appreciation for the importance of balancing the tradeoffs between electricity availability, cost, environmental impacts, etc., in general, and the tradeoffs between specific supply mix options.
- Many suggestions were offered to fill this perceived information gap:
    - Some suggested using real-time metering of electricity and multi-residential electricity metering so that people become aware how much electricity they are using.
    - Some suggested price discriminations and price signals so that people know "by their pocketbooks" how much energy they are using.
    - Others suggested that the Government build alliances with trusted and informed members of the media.
- Participants commented that a more informed public allows for better stakeholder engagement. Several recommended societal dialogue about the importance of electricity related issues, specifically concerning the cost tradeoffs and cost-tolerances, and, to a lesser degree, the environmental tradeoffs and environmental tolerances.
    - For example, Participants in one group noted a perceived difference between what politicians believe and how stakeholders and the public values coal as a supply mix option.
- Participants believed it was the role of OPA to provide this information to the customers and ratepayers in an objective and balanced manner. They also noted that the government tends to

set the information agendas -- focusing on renewables and CDM – and does not provide the whole story.

5. Breakout Group Assignments – Sessions Two and Three

The following highlights from Sessions Two and Three reflect statements made by individual Participants during discussions. Again, comments should not be interpreted as consensus unless specifically indicated.

After a presentation by Amir Shalaby on specific challenges in developing an appropriate supply mix, the groups reconvened and worked through a series of questions. Each group selected a spokesperson who presented highlights from the group discussions.

Groups 1 and 2 joined together (as some Participants had to leave at noon) and worked through the challenges of building an appropriate supply mix, first, in the short term (2005-2015), then in the longer term (2015-2025). The following questions were asked in Sessions Two and Three as they pertain to each timeframe:

1. What barriers do you see to achieving an appropriate supply mix?

2. Given the barriers defined, what are the toughest choices – tradeoffs – that will need to be made?

3. What strategies would you recommend for addressing these challenges?

Groups 3 and 4 addressed issues related public policy challenges in Session Two, guided by the following questions:

At present, a number of federal and provincial departments influence Ontario electricity policies, including those related to long term planning. Soon municipalities will play a greater role in electricity planning. Thinking about OPA's mandate to develop a long term electricity plan for the Province:

1. *What are the key challenges regarding electricity policies that need to be addressed if Ontario is to have a reliable electricity system both short and longer term? (open question)*

2. *What are the most significant inconsistencies between provincial departments? How might these be addressed?*

3. *What are the most significant inconsistencies between government levels – federal, provincial and municipal? How might these be addressed?*

4. *What are the most significant challenges for municipalities given their expanding role? How might these be addressed?*

In Session Three, Groups 3 and 4 addressed challenges related to private versus public interest, guided by the following questions:

1. *What are the key challenges regarding private vs. public interests that need to be addressed if Ontario is to have a reliable electricity system both short and longer term?*

2. *What strategies would the group recommend for addressing these challenges?*

All of the groups were asked:

What considerations does the group have for OPA to take forward as it prepares its advice to the Minister?

Supply Mix and Electricity Planning Challenges

The challenges of electricity planning in the short- and long-term were the primary focus of discussion in the combined Groups 1 and 2. Since these issues are often linked with public policy challenges (the assigned topic in Groups 3 and 4), many of the topics also arose in Groups 3 and 4. Highlights from discussions include the following:

- Participants in all groups noted that supply mix advice is more than just choosing among fuels. It must include fuel type, size and location. There was general agreement in the groups that the supply mix challenge is more significant, in the short- and long-term, than people generally recognize. One Participant's advice to the Minister was to "start acting like we're in an emergency."
- A primary theme of the Workshop was the time-frame of planning. The upcoming Integrated Power System Plan (IPSP) is not a one-time plan and must be continuously revised to reflect the changing energy needs, life-span of existing technologies, new technologies and changing policies. To this end, some suggested that OPA should "keep its finger on the pulse of technology and the market."
- Risk and uncertainty were mentioned by Participants in all groups. Commenting on Amir Shalaby's presentation of the challenges of supply mix planning, Participants in two groups commented about the uncertainty that the supply mix options already in planning in the short term were all feasible and wondered about contingency planning.
- Many Participants emphasized that the real risk is in the implementation of the Integrated Power Supply Plan (IPSP) in the short- and long-term:
    - Difficulty siting of both transmission and generation facilities was mentioned as a significant barrier. Siting issues were raised at a number of points throughout the discussion in all groups.
    - Labour shortages (to build and maintain new generating capacity) was raised as a critical issue, as Ontario will lose 50% of its skilled worked force in the next five years, primarily through retirement. Participants suggested that there must be government action now to encourage investment in this technical infrastructure.
    - Many Participants talked about the importance of including risk in the supply mix advice, especially concerning planning for catastrophic events. Specifically mentioned was the impact of weather on Ontario's need to rely on other Provinces and the United States for electricity supply.
    - Another primary theme of the Workshop was the investment risks of planning, siting and constructing facilities. This topic is discussed in further detail in *Public Policy Challenges*.
- When thinking about strategies for going forward with the long-term plan, Participants in Groups 1 and 2 stressed the following points (echoed in Groups 3 and 4 discussions).
    - The need to streamline the regulatory process. As one Group stated, "reduce the number of steps and rationalize the ones that are left." One suggestion was to enact a "task force" approach, allowing Ministries that have typically dealt with energy issues in isolation to work together more holistically.
    - The need to elevate electricity and energy issues in public dialogue.
    - The need to engage a long-term commitment to community engagement process.
    - The need to protect the electricity planning from changing governments. This point was also emphasized in Participants' advice to the Minister.
    - One group focused on issues of financing and called for creative financial measures, such as loan, grant and portfolio funding.

Public Policy Challenges

Issues surrounding the public policy challenges of electricity planning and implementation were the primary focus of discussion in Groups 3 and 4. Because these issues are often intricately linked with public policy issues (the assigned discussion of combined Groups 3 and 4), many of the same topics arose in Group 2 as well. A key theme of the Workshop was the relationship between the three levels of

government – federal, provincial and municipal. Participants discussed their influence on the efficacy of electricity planning and implementation. Highlights from these discussions include the following:

- Participants noted the challenges of alignment between and among the three levels of government and recognized that the three levels have different priorities – the Federal government has Kyoto obligations, the Provincial government has an obligation to supply electricity, and Municipal government is focused on economic development and electricity siting.
- All of the groups discussed the importance of and need for open and cooperative inter-Ministerial relationships between such entities as the Minister of Energy, the IESO, the Minister of Public Infrastructure, Minister of Finance, Minister of Natural Resources (environmental assessments), and every Deputy Minister in the Cabinet.
    - Participants in two groups mentioned the "silo effect"; i.e., Ministries acting alone and not talking to one another.
- International policies, especially Kyoto obligations and U.S. environmental standards, were cited as public policy challenges.
- Municipal government involvement in electricity planning was a particular focus of discussion in all groups. They felt that municipalities have not had to consider energy previously, and that were not yet equipped to properly handle these decisions.
    - The Municipality Planning Act, which does not do enough to shift the barriers of effective implementation at the municipal level, was specifically cited.
    - Participants commented that municipalities often do not appreciate the gravity of electricity needs and that this lack of understanding leads to NIMBY-ism.
- Participants commented that the above-noted challenges are a major constraint on effective electricity planning and implementation in both the short- and long-term.
    - All Groups specifically mentioned the regulatory approval process and linked the challenge to those noted above. One group suggested that the number one problem is "getting anything done."
    - Two issues that arose in most groups was the timing of the approval process and regulatory certainty. Participants stressed that investors need more certainty in the approval process and that certainty (in other words, if all the requirements are met, approval will be granted) was a bigger constraint than timing. One Participant suggested: "One process. One decision. One appeal. Certainty is the key."
    - Participants in all groups acknowledged the societal role of the approval process. One group emphasized the appropriate forum for local public discussion that the approval process provides, and suggested that removing this process would likely lead to greater problems.
- Workshop Participants in all groups offered suggestions for improving Municipal involvement in electricity issues, including the following:
    - There should be a move toward differential pricing of transmission or localized marginal pricing – that is, communities that house generating facilities would pay less for their electricity.
    - OPA should respect the local values and stress the tangible benefits of generating capacity, such as jobs and economic benefits.
    - Municipalities should be encouraged to look more holistically at land use and energy use – as they do for water use.
    - One Participant indicated that there is a lot of local leadership and interest in energy planning and that concrete tools are needed to enable local leaders to take action.

Public and Private Interests and NIMBY

Two specific public policy challenges – public vs. private interests and NIMBY – were raised in all groups' discussions and were intricately linked to other major discussion topics. For Participants, these issues should permeate any discussion of electricity planning, including OPA's supply mix advice.

- The question of public interests vs. private interests was a primary theme, emerging in all groups.

    - One group asked whether electricity is a public or private good, calling it a question for open debate.
- Another major theme of the workshop was the interplay between societal and private interests.
    - Challenges related to NIMBY-ism were mentioned in each major discussion. NIMBY-ism was noted as a particular challenge at the municipal level. These issues were closely linked with discussion about informing the public.

OPA's Role and Advice to the Minister

Participants in all groups mentioned the role of OPA in electricity planning. The following highlights emerged from discussions about advice to the Minister.

- Participants in all groups acknowledged the challenges OPA faces. They applauded OPA's efforts thus far and encouraged the Minister to support OPA in whatever capacity it needs to fulfill its mandate.
- Participants in all groups noted that OPA's role is to lay out the options for the Minister and not be too prescriptive in its advice.
    - Rather than prescribing specific percentages or supply options, they suggested OPA prescribe more broadly with respect to issues of diversity and flexibility. OPA can provide leadership in creating a shared understanding of these issues and lead in acceptable solutions. One group suggested that OPA should "create the rules, not the roadmap."
    - Congruently, many Participants thought that the market would take care of the details if the values put forth are consistent with social mandates.
    - A few commented that the market would not reflect social mandate. Renewables were cited as an example where a social mandate concerning environmental impacts requires expensive solutions that would not be feasible in the market alone.
- Two groups urged Government to leave the planning and implementation to expert, independent agencies. One group noted, "Government is good at responding to what people say they want, through broad policy, but lousy at getting something done. So leave the details to the experts." There was recognition that this is difficult in practice.
- Participants in two groups also commented on the narrow scope of OPA's mandate: to provide advice to the Government on electricity policy. One group stressed that OPA cannot and should not address other challenges, such as industrial policy.
- In offering advice, Participants suggested that key Provincial Ministers and staff should be engaged in the supply mix process as soon as possible – before the Advice is sent to the Minister – and that technical training might be offered to help them understand the report.
- Participants stressed the importance of the Minister's full understanding of the integrated nature of the supply mix advice and the implications of policy decisions. One group commented that the background research should be made transparently available to the Minister.
- Participants emphasized that OPA must be prepared to play an active communication role to explain (and defend) its advice in a public forum.
- Similarly, some Participants commented that the government must be transparent in their decision making process.
- There was concern expressed by all groups about how the Supply Mix Advice would be used by the Minister. Some Participants stressed that the Government must make tough choices and must avoid "cherry picking" among supply mix elements and options. They noted that the supply mix portfolio was a system solution, so it was not possible to "cherry pick" without having a significant negative influence on other elements of the system.
- Participants suggested that energy-planning must be non-partisan – "take the political risk out of an essential service." Again, it was noted that this is difficult in practice.

Appendix 1

Focusing Decision-Making and Action to Create High Value Results

Success often depends on how well leaders address the decision-making of key groups, both inside and outside their organizations. Such groups can include citizens, customers (current and prospective), employees, community residents, regulators and special interest groups.

The stakes for people's decisions can be high, as they are when it comes to:

- Addressing environmental hazards and impacts.
- Shaping public policies.
- Assuring the success of beneficial new products or services.
- Siting, modifying, or closing stationary or linear facilities.
- Changing management or industrial practices.

Decades of research and experience show that decision-making is primarily influenced by initiatives and communications; that is, deeds and the messages about them. Too often, however, strategies for both are driven by intuition and myths about people's thinking, beliefs, and how people will process communications. To perform as intended, strategies and communications must be grounded on deep insight into people's full thinking about the topic or issues at hand.

At Decision Partners®, we provide the requisite insight and, as appropriate, the guidance and implementation services needed for its successful application.

An international team of management professionals and scientists, our mission is to help assure the successful use of beneficial ideas, knowledge, products and services. We are the world leader in advanced behavioural decision research, strategy and communications services for focusing human decision-making and behavior. Our methods draw from current understanding in the relevant academic disciplines, including decision science, risk perception, risk communication and marketing science.

Our hallmark is our exceptionally broad experience in expert modeling and mental models research. Expert models integrate expert knowledge. Mental models research reveals and characterizes in-depth the tacit webs of belief that guide all people's decision-making. Decision Partners has the largest inventory of expert models and mental models research results worldwide.

Working independently, or with a member of our growing network of application professionals, we serve public, private and not-for-profit organizations internationally. Our experience spans a broad spectrum of industry and government organizations in major sectors, including automotive, chemical, consumer products and services, defense, energy, environmental management, forest products, health care, information systems/technology, mining, plastics and transportation.

Contact information: For more information about Decision Partners, our capabilities, services and experience, please contact: Gordon Butte or Sarah Thorne at 1-877-588-9106 or gbutte@decisionpartners.com; sthorne@decisionpartners.com.

Background on the Mental Models Approach

Behaviour is Guided by Mental Models

Decades of research have shown that tacit webs of beliefs that have come to be called "mental models" guide people's behaviour. People draw on their mental models to make inferences about problems that come to their attention through various communications.

In the past 15 years, researchers have used the mental models orientation to address challenges presented by lay-people's understanding of complex issues and processes, such as risk and risk management. This work, and other research, has shown that to change people's beliefs and behaviours, one must understand and change their mental models.

What Are Mental Models?

Mental models is a well-established concept in psychology and has been the focus of extensive research.[2] A person's "mental model" can be thought of as a complex web of deeply held beliefs that operate below the conscious level. Mental models affect how an individual defines a problem, reacts to issues and makes decisions about messages and options concerning topics that come to his or her attention through communications. Mental models tend to prevent people from seeing alternative perspectives and define boundaries of thought and action, thereby limiting people to familiar patterns of reasoning and action.

Effective analyses of mental models can identify how different groups of people think about and respond to a variety of topics, including benefits and risks associated with activities, plans, or proposals. The method relies on data collected from experts and stakeholders, typically through focused interviews with individuals conducted in person or by telephone.

The Challenge of Effective Communication

Experts and laypeople alike have challenges associated with their thinking about how to communicate on topics related to choice, risk or change. For instance, research and experience have shown that experts' beliefs about what to communicate on issues, to whom, and how can represent barriers to effective communication. Experts may predict that laypeople will:

- Be "irrational" about risks and, therefore, be inherently difficult to "reason" with.
- Need to be educated in order to judge risks and benefits appropriately.
- Be unable to add to the expert task of defining and solving problems.
- Have information preferences and biases for interpreting communications that can be easily predicted.
- Want to erode authority in order to shift power away from experts.

However, over the last 30 years, it has become evident that:

- When designing communication strategies, speculation about people's interests and priorities is naïve at best and often risky.

[2] For example: Johnson-Laird, P. N. (1983). Mental Models. Cambridge, MA: Harvard University Press. Atman, C.J., et al. (1994) Designing risk communications. Risk Analysis 14(5): 779-788; Bostrom, A. et al. (1992) Characterizing mental models of hazardous processes. J. Social Issues 48(4): 85-100; Fischhoff, B. et al. (1997) Risk perception and communication. In: Detels, R. et al. (eds.) Oxford textbook of public health. London: Oxford University Press, 1997. Pp. 987-1002.

- Laypeople typically address decisions from a different conceptual framework (mental model) than experts and use different terms.
- They often want and expect to participate in the process of defining options and making tradeoffs.
- And neither experts nor laypeople can ignore scientific uncertainty.

It is well established that people's mental models vary in important, but often unpredictable ways, and that their decisions are strongly affected by these mental models.[3] Through mental models research, we can discover:

- What people know that is correct and essential to making an informed decision.
- What they misunderstand that is consequential.
- What they do not know that is consequential.
- What they want to know and is important to them.
- What criteria they use to judge the trustworthiness and competence of people, organizations, and communications.

Understanding People's Beliefs

A Comparison of Opinion Polling, Focus Group and Mental Models Research Approaches

Our Chief Scientist, Dr. Baruch Fischhoff, developed the following comparison of opinion research, focus group research and our Mental Models approach. Baruch is also University Professor at Carnegie Mellon University with the Department of Engineering and Public Policy there. He chairs Decision Partners' Scientific Advisory Committee. Baruch is a world-renowned authority in risk perception and risk communication and is a major contributor to the worldwide scientific literature in these fields.

Research has demonstrated that the complexity of people's thinking makes it impossible to predict the effects of communication on people's beliefs without empirical testing. Testing methods must suit the task assigned to them. There are three major interview-based approaches for understanding people's beliefs. They are:

Opinion polling -- well suited to measuring opinion in a sample. Such research typically poses a fixed set of questions to a select group of people. Responses are subjected to statistical analyses, which must then be interpreted in terms of how respondents are believed to have interpreted the questions, and might have responded to alternative interpretations.

Such an approach is useful when only discrete answers to particular questions are needed. It is also useful when precise estimates of the frequency of specific beliefs in a population are required. Opinion research typically tries to capture what respondents believe, not why they believe it. It is not suited to learning about topics that are important to respondents but lie outside of the questions posed in the interview.

Focus groups -- most useful when studying beliefs that are normally shaped and expressed in groups with a composition like those of the focus group. They are also useful when it is not important to be able to replicate a procedure or analyze data from the group session.

By allowing free expression of beliefs, focus groups can get closer than opinion polling to understanding what a group believes and why it holds those beliefs. The approach is inherently limited by the effects that specific group interactions have on what participants do and do not say, as well as which lines of thought can and cannot be fully pursued by individual members. In focus groups, the opinions that participants

[3] Fischhoff, B. and Downs, J.S. (1997) Communicating foodborne disease risk. Emerging Infectious Diseases 3(4):489-95.

express depend on the skills and the agenda of the moderator. They are typically interpreted and summarized impressionistically by the moderator.
Neither method is well suited to characterizing communication networks within a "community of interest".

The Mental Models (or "dialogue") Method -- involves individual, one-on-one interviews, leading participants through a jointly determined agenda of topics. The one-on-one situation helps to approximate the decision-making environment within which most people form their attitudes toward an organization or industry.

The method allows free expression and encourages elaboration on topics in order to reveal individual perspectives at considerable depth. Interviewees can readily raise topics that most interest them, but which may be outside of specific questions. Because a full set of beliefs is elicited from each interviewee, structured analyses are possible. When done well, analysts can identify what people believe and why they believe it. They are also able to compare analyses over time and provide insights into why beliefs may have changed.

Properly done, the Mental Models Method can produce rich results more efficiently than can the equivalent time and effort invested in opinion polls or focus groups.

Twinned with a structured approach to developing an interview sample, it can help characterize communication networks in communities where it is applied. It can also be used effectively in combination with opinion surveys and focus groups. In such cases, Mental Models research is done first in order to design properly constituted focus groups and opinion research instruments.

Finally, the process of conducting Mental Models research is a respectful one. We often find that the interviewers themselves begin to create relationships with participants like those that our clients hope to create with the larger community. Such research has demonstrated that even participants who are skeptical of a company or industry often express satisfaction with a process that allows both parties to hear one another out.

Method Comparison Summary

1. Mental Models, or "focused interviewing", leads an individual through an agenda of topics, allowing free expression and encouraging elaboration on topics, in order to reveal individual perspectives at depth. Because a full set of beliefs is elicited from each respondent, structured analyses are possible. These involve the coding of interview transcripts and a statistical summary of beliefs. When done well, analysts are able to identify what people believe and why they believe it.

2. Group Discussion, often called a "focus group", leads a small set of individuals together through an agenda of topics, formulated in a general way to allow free expression, within the constraints of group dynamics. Opinions are often interpreted and summarized impressionistically. One challenge this method presents is the need to sort out group influences and lines of thought that could not be pursued fully by the individuals.

3. Opinion Polling poses a fixed set of structured questions on an individual basis to a large number of people. Answers are directly subjected to statistical analyses, with no intervening interpretation. The results of these analyses must then be interpreted in terms of how respondents understood the questions and might have responded to alternative interpretations. Opinion polling typically reflects what people believe, not why they believe it.

Decision Partners' method can be used with any of the three general methods described here. For example, where individuals' decisions are formulated and expressed in group settings, then appropriately constituted focus groups are possible. Often, a structured survey can be built upon our open-ended procedures, in order to collect larger sets of data.

Appendix 3

DECISION PARTNERS

OPA Stakeholder Consultation
Mental Models Interview Protocol Outline

Project Summary

In September and October 2005, Decision Partners interviewed approximately 62 stakeholders, both Industry and Non-industry, as part of our stakeholder consultation work. The purpose of the consultation was to help OPA professionals better understand stakeholder interests and priorities with respect to the supply mix and to enhance OPA's advice to the Minister on the appropriate supply mix to meet anticipated demand in the Province.

The protocol outline that follows includes text used by interviewers to solicit participation in the interview and text used during the interview process to provide context for the flow of the interview (noted in italics).

Protocol Outline

Solicitation

Hello, this is <name> with Decision Partners. As you may be aware, we have been asked by the Ontario Power Authority (OPA) to conduct stakeholder consultation in support of OPA's preparation of advice to the Minister of Energy on electricity supply mix. Stakeholder consultation will help OPA professionals better understand stakeholder interests and priorities with respect to supply mix. OPA will use this input as it prepares its advice to the Minister, which will be delivered December 1 of this year.

Part of this consultation involves confidential interviews with people like you who have an interest in electricity related issues. The interviews will be done over the phone. Our conversations will be strictly confidential and will take about 30 - 45 minutes. If you are interested, we will schedule at a time that is convenient for you. Would you be willing to participate in an interview?

Introduction

(When calling back...) Hello, this is <name> from Decision Partners calling to keep our appointment to interview you on electricity supply mix issues. Is now still a good time for us to talk?

Thank you again for participating in our research. As I mentioned, the purpose of this interview is to help OPA professionals better understand stakeholder interests and priorities with respect to supply mix. OPA will use this input as it prepares its advice to the Minister of Energy.

Our conversation today should take about 30 - 45 minutes.

I have a list of questions to help guide our discussion, but please feel free to raise any related topic that comes to mind as we go along. In this kind of an interview, there are no right or wrong answers, and all of your comments will add value to the research.

Before we start, I want to assure you that your specific comments will be kept confidential to Decision Partners. We will provide OPA with a consolidated report of the findings that does not identify any individuals by name, or the specific source of any comments by name or organization.

In order to ensure that my notes of our conversation are accurate and complete, I'd like to ask your permission to tape-record our conversation, but I would like to stress again that the responses will be kept confidential. The tape will only be used by researchers at Decision Partners and then destroyed at the

conclusion of the research. No personally identifying information will be passed along to OPA. May we proceed on that basis?

Opening

The Ontario Power Authority's, or OPA's, mandate is to develop a plan for ensuring an adequate, long-term supply of electricity to Ontario. As part of this undertaking, OPA has been directed by the Minister of Energy to prepare advice to the Minister on electricity supply options suitable for meeting Ontario's energy needs for the next 15 to 20 years. Our interview will focus on this task, which we will call supply mix advice.

Broadly, I'd like to get your thoughts on:

- *Influences on the need for electricity in the Province;*
- *Considerations on the balance of a supply mix portfolio;*
- *Considerations on influences on the quality of advice from OPA to the Minister of Energy;*
- *Any other thoughts you might have.*

Influences on Need for Electricity in Ontario

Let's start by talking broadly about the need for electricity in Ontario in the next two decades and the factors influencing that need that you believe are important for OPA to address as it develops its supply mix advice.

Questions in this section address interviewees' thoughts about the need for electricity in Ontario:

- The current societal need for electricity in Ontario.
- The major factors shaping that need and which factor would be the most important.
- The future need for electricity in Ontario (next 15 or 20 years) and the major factors shaping that need.
- The relative importance of the following factors:
    - availability of electricity – keeping pace with Ontario's growing energy demands
    - stability of electricity rates
    - reliability of electricity service – minimizing the occurrence of electricity outages due to demand overload or damage to transmission lines and maintenance problems
    - environmental responsibility – efforts to reduce the impact of electricity generation and transmission on the environment
    - market stability – a predictable market structure for buyers, sellers, generators and distributors

Balance of Supply Mix Elements

Let's move on to discussing the supply mix portfolio in more detail. The Minister has specifically asked OPA to consider three elements in its supply mix advice: conservation and demand management, renewable energy sources and advanced technology conventional sources. Thinking about those, Id like to get your thoughts on a balanced supply mix portfolio. I am going to ask you to allocate a portion of 100 percentage points of the supply mix to each of the three elements. Let's take the three elements one at a time, in the order outlined by the Minister . . .

Questions in this section address:

Conservation and demand management

- How the term is initially understood.
- How much of the total supply mix (100%) would be allotted to CDM.
- Rating the importance of various CDM initiatives:

- Education programs.
- Economic incentives.
- Government standards and regulations.

Renewable energy sources

- How the term is initially understood.
- How much of the total supply mix (100%) would be allotted to such things as electricity from wind, solar, biomass and small hydroelectric projects.
- What renewable energy sources would be included.
- What would not be included.

Advanced technology of conventional sources

- How the term "conventional sources" is initially understood.
- How the term "advanced conventional energy sources" is initially understood.
- How much of the total supply mix (100%) would be allotted to such things as natural gas, large scale hydroelectric, nuclear, coal and oil and distributed energy sources
- What advanced conventional energy sources would be included.
- What would you not include?

- Most important benefits the suggested portfolio.

- Possible drawbacks of the suggested portfolio and how these might be addressed.

- Speculation on OPA's recommended portfolio mix (% CDM; % renewables; % conventional supply sources)

Influences on Supply Mix Elements

My next questions focus on the things that influence the development of OPA's supply mix advice, namely: the Economic and Environmental Impacts, Quality of Stakeholder Consultation Process, and External Pressures. Let's take them one at a time.

Questions in this section address:

- Economic and environmental impacts that are important for OPA to consider.
- The relative importance of the following environmental and economic impacts:
  - the cost of producing and distributing energy;
  - performance – eg., capacity and efficiency of electricity generation;
  - the economic and environmental impacts of electricity transmission and distribution;
  - the market structure for buyers, sellers, generators and distributors;
  - regulatory uncertainty – the difficulty of predicting the economic and environmental regulations that will affect energy production;
  - political uncertainty – Ontario and Canada;
  - life-cycle assessments;
  - social acceptability;
  - other impacts.

- The nature and substance of input from people or groups outside OPA who have a significant interest in electricity issues and the influence on the supply mix advice.

- The relative importance of the following factors for OPA to consider:
  - stakeholder motivation for supplying input;
  - socio-economic factors, such as education or income;
  - regional differences in Ontario:
  - stakeholders' political affiliation.

- The relative importance of other types of external pressures on the quality of the supply mix advice, including:
    - the influence of government or political figures.
    - the influence of the media.
    - the influence of the electricity industry.
    - economic pressures.
    - pressures from other provinces?
    - international pressures?
    - the importance of considering the possibility of a catastrophic event

Quality of Supply Mix Analysis

This section asked interviewees to think about everything discussed, and state the most significant influences on the quality of OPA's analysis of supply and demand options?

Closing

The interviewer thanks the interviewee and asks him or her to add:

- Any additional topics not discussed that should be factored into OPA's advice to the Minister;
- One piece of advice he/she would give the OPA as it goes forward in preparing its advice to the Minister on supply mix.

Before we close, I'd like to let you know that we are working with OPA to plan a workshop on November 10 to enable interested stakeholders to review the input received through the stakeholder consultation process and discuss the substance of OPA's advice to the Minister of Energy. If you are interested in participating, I would need your approval to pass your name along to OPA. Would you like to be contacted by OPA about participating in this workshop?

ANALYSIS OF WIND POWER POTENTIAL IN ONTARIO

Prepared for
Ontario Power Authority

by
Helimax Energy Inc.

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helimax

Wind energy consultant for the world

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SYMBOLS AND DEFINITIONS

agl	above ground level
bathymetry	the measurement of the depth of the marine floor from the water surface; the marine equivalent of topography
capacity factor	Ratio of the average power produced by a wind plant over a year to its rated power capacity. It is calculated as the ratio of energy delivered over the total wind plant capacity multiplied by the total hours in a year.
Dx	distribution
GIS	Geographic Information System
km	kilometre
kW	kilowatt
m	metre
m/s	metres per second
mesoscale	atmospheric phenomena having horizontal scales ranging from a few to several hundred kilometres
MNR	Ministry of Natural Resources of Ontario
MW	megawatt
NA	not applicable
OPA	Ontario Power Authority
TWh	terawatt-hour
Tx	transmission

Unconstrained potential:	Raw onshore wind energy potential
Constrained potential:	Onshore wind energy potential excluding potential in specified exclusion zones and related buffers
Technical wind power potential:	Constrained potential within specified distances to either the transmission or distribution networks

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1 INTRODUCTION

In May 2005, the Ministry of Energy of Ontario requested advice from the Ontario Power Authority (OPA) on the future "supply mix" of electricity for the province. As outlined by the Ministry, the OPA's advice, to be delivered on December 1st, is to be based on internal and external sources of information.

As part of the OPA's public consultation, the Canadian Wind Energy Association (CanWEA), representing Canada's wind energy industry, took the opportunity to provide insight on the potential contribution of wind energy in the future supply mix of the province. The brief prepared by CanWEA for the OPA recommended that wind power could play an important role in providing Ontario with significant quantities of safe, reliable renewable energy.

In order to supplement its research on the role wind power could play in Ontario, the OPA recognized that it needed to more fully evaluate the potential for wind power development in the province and, in addition, to research the proximity of good wind resource areas to transmission and distribution systems. The objective was to understand how much wind was in close proximity to the grid and what the tranches of proximity were for connecting additional wind.

The OPA contracted Helimax Energy Inc. ("Hélimax") for this task based on its expertise in having established the Ontario Wind Atlas for the Ministry of Natural Resources of Ontario (MNR), its track record of performing wind resource analysis for the Régie de l'énergie in Quebec (Quebec energy board), and its experience working with CanWEA and with wind developers around the world.

For the proximity analysis to be completed, the OPA facilitated access to Hydro One Networks Inc.'s GIS (Geographic Information System) electronic data for its transmission lines and distribution stations and to MNR's GIS wind atlas data. Specifically, Hélimax was asked to perform an analysis of the following:

- The total technical wind power potential capacity in the province in the areas identified as having above-average wind speeds;
- The geographical distribution of the technical potential within the province according to specific *pre-defined areas*;
- The total technical potential within *environmentally sensitive areas* of the province;
- The proximity of the technical potential with respect to both the transmission lines and distribution stations.

Hélimax has developed a methodology to perform a "high-level" assessment of the potential within a given province. This consists of combining the results of mesoscale wind speed maps with a land use and topographic analysis. By performing a land constraint evaluation and superimposing the results on the wind speed map, it is possible to quantify the technical potential within the province and to understand the geographical distribution of the resource.

The provincial mesoscale wind speed map used in the analysis is shown at the end of this section.

A detailed description of the methodology used to produce the results is presented in Section 2. Section 3 presents the results of the analysis. First, results for the constrained and technical potential for the province-wide analysis are presented. Then, these technical potential results are broken down by region. Finally, a detailed analysis of the technical potential is presented.

The Pre-defined Areas and Environmentally Sensitive Areas as defined by the OPA, as well as the Constraints identified by the OPA are given below.

Table 1-1: Predefined and Environmentally Sensitive Areas

Pre-defined Areas		Environmentally Sensitive Areas
Province-wide Areas	**Regional Areas**	
• Entire province • North of the 50th parallel • Crown land • Private land • First Nations land	• Bruce Peninsula • Lake Erie – East • Lake Erie – West • Lake St. Clair • Lake Ontario – North Shore • Georgian Bay – South • Georgian Bay – North • Lake Huron Shore • Lake Superior – North • Lake Superior – South • Central Southwestern	• National and Provincial Parks • Environmental Protected Areas • Niagara Escarpment • Oak Ridges Moraine

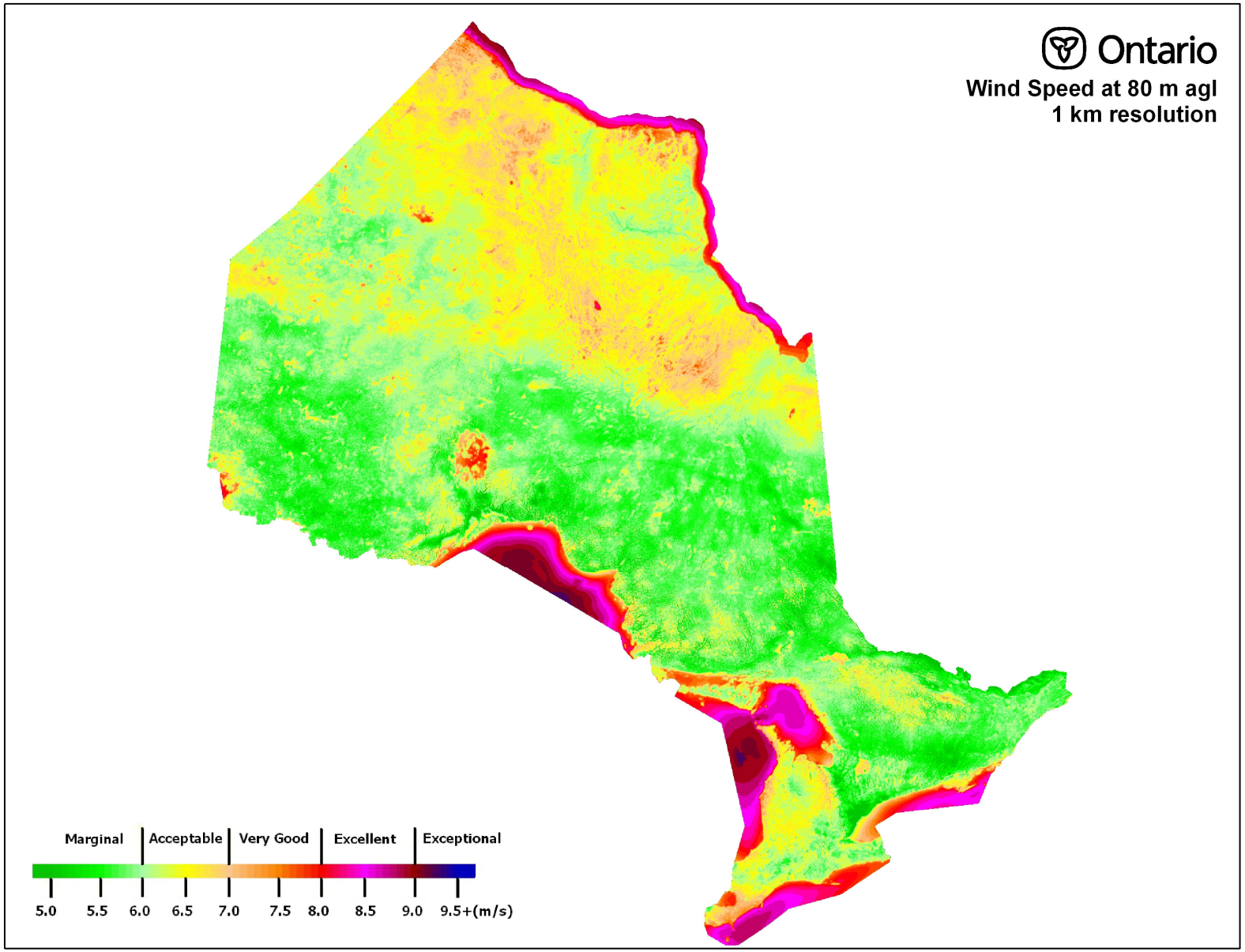
Constraints

In performing the analysis, areas where wind development would not be feasible are subtracted from the total unconstrained wind resource in order to arrive at a "constrained" potential. The elements included in this constraints analysis were selected by the OPA and are as follows:

- Hydrography
- Roads
- Railroads
- Slopes
- Buildings
- Waterways (for offshore analysis)
- Marinas (estimated for offshore analysis)
- Offshore protected areas (estimated for offshore analysis)
- Important Bird Areas (for offshore and pre-defined areas analysis)
- Provincial parks (for pre-defined areas analysis)
- National parks (for pre-defined areas analysis)

Constraints not considered in this analysis include, amongst others, those related to local regulations such as zoning and land use restrictions, land rights, and social acceptability considerations. Social acceptability is a significant source of uncertainty, and some areas that have significant potential will face strong local opposition due to concerns about effects of turbines on personal enjoyment (e.g., recreation viewscapes, atheistic issues and noise), concerns about property values and effects on avian species. These should be considered before estimating the total "developable" wind potential in the province.

In order to determine the "developable" wind potential, the OPA might find it useful to use adjustment coefficients that range from 0.05 to 0.5, depending on the area and upon the degree to which local opposition may result in decisions to not proceed with development.



Map 1: Ontario Mesoscale Wind Speed Map

2 METHODOLOGY

The calculation of the technical wind energy potential within the province was done using a programmed Geographical Information System (GIS) application tool and available geospatial and wind resource data from the Ontario Ministry of Natural Resources (MNR) and data from Hydro One Networks Inc. Several technical, non-technical and environmental constraints were considered with the aim of approximating the technical wind potential of Ontario. An overview of the technique used to quantify the potential MW capacity for Ontario is given below.

2.1 Overview

The first part of the calculation process involved analyzing and querying available mesoscale wind speed data from MNR's wind resource atlas. This was done at 1-km resolution to vet and extract areas with good and promising wind energy potential. For the Ontario region, wind industry proponents consider these to be areas with average annual wind speeds greater than 6.5 m/s. The 80-m agl (above ground level) data set was chosen for the OPA analysis because this is considered a typical turbine hub height.

The second part of the process involved cross-referencing the "good and promising" wind areas with respect to land-use and topographic information. This constraints analysis included the identification of exclusion zones and related buffers, in order to rule out areas where wind farm development may not be technically feasible or environmentally permitted.

The final combined analysis considers distance of the "constrained potential" to existing transmission and distribution systems and identifies lands which are potentially suitable for wind energy development. It must be noted, however, that this potential is a "technical potential', and does not account for municipal zoning and land use considerations or other local factors that might impede development of wind power.

The surface area of these "suitable" areas (presented in km^2) can be calculated and converted into technical megawatts (MW) potential by estimating a specific MW capacity per square kilometre. Based on an estimate that 5 MW of wind can be installed per square kilometre of suitable area, Hélimax estimated the total technical potential in each of the pre-defined areas and environmentally sensitive areas.

The value of 5 MW per square kilometre is an estimate based on expert knowledge and previous constraints evaluations for other jurisdictions and wind proponents. It should be noted that this value is a rough estimate that is adequate only for site prospecting. The value is not necessarily representative of any particular site.

Lastly, using an estimated net capacity factor reasonable for the considered wind regimes, the total amount of energy available for wind power generation is estimated. Hélimax, in its expert judgement, uses an estimated average capacity factor of 31%. Again, this value is not necessarily representative of any particular site.

2.2 Mesoscale Map

In 2005, the Ministry of Natural Resources (MNR) published a mesoscale map for the entire province of Ontario at a 1-kilometre resolution. Details of the wind speed map can be found on its website at www.ontariowindatlas.ca . Completed at a resolution of 1 kilometre, the mesoscale map used for this analysis is suitable only for preliminary estimates. At the time of this study, only the 1-kilometre resolution wind speed map of the province was available. A copy of the map is provided at the end of section 1.

The wind classes considered for this analysis correspond to wind speeds greater than 6.5 m/s at 80 m agl. It is assumed for the purposes of this analysis that areas with average wind speeds of less than 6.5 m/s will not be developed.

2.3 Data Sources

The GIS (Geographical Information System) data came from two main sources. The wind atlas was provided to Hélimax by the Ministry of Natural Resources (MNR). The transmission lines and distribution station data was provided by Hydro One Networks to OPA, who in turn provided it to Hélimax for the purposes of this study.

Other information was obtained from the OPA or publicly available databases. The data layers and their respective sources are presented in the tables below.

For the districts of Cochrane, Nipigon, Red Lake and Sioux Lookout, Hélimax has extracted hydrography data from The Ontario Provincial Land Cover Database.[1] The hydrography data provided by the MNR for those districts was not complete.

Slopes were derived from the elevation data of the Shuttle Radar Topographic Mission[2] (SRTM) at 90-m ground resolution and re-sampled to 1 km.

Boundaries of the pre-defined areas were defined by Hélimax using information received from the OPA.

Table 2-1: GIS Data Layers and Sources - Constraints

Layer	Source
Hydrography (waterbody or watercourse)	Ontario Ministry of Natural Resources / OPLCD
Road	Ontario Ministry of Natural Resources / National Road Network (NRN)
Railroad	Ontario Ministry of Natural Resources
Building	Ontario Ministry of Natural Resources
Transmission line and distribution substation	Hydro One Networks Inc
Slope	United States Geographical Survey (USGS)
Provincial Park	Ontario Ministry of Natural Resources
National Park	Ontario Ministry of Natural Resources
Important Bird Area	IBA Program – BirdLife International
Waterway	Bureau of Transportation Statistics (USA)
Bathymetry	National Oceanic and Atmospheric Administration (NOAA)

[1] This database was created by the MNR and is available at: www2.lib.uoguelph.ca/resources/gis/PLC/index.cfm.
[2] www2.jpl.nasa.gov/srtm/

Table 2-2: GIS Layers and Sources – Environmentally Sensitive Areas

Environmentally Sensitive Area	Files Used	Description	Source
Provincial Parks	Natlpark	National Park	OMNR_LIO Warehouse
	Provpreg	Provincial Park, Regulated	OMNR_LIO Warehouse
Environmental protected areas	Ansi	Areas of Natural and Scientific Interest	OMNR_LIO Warehouse
	Conrvreg	Conservation Reserve, Regulated	OMNR_LIO Warehouse
	Consvare	Conservation Area	OMNR_LIO Warehouse
	Esa	Environmentally Sensitive Area	OMNR_LIO Warehouse
	Natwld	National Wildlife Area	OMNR_LIO Warehouse
	Ngonatrv	NGO Nature Reserve	OMNR_LIO Warehouse
	Nhervala	-	OMNR_LIO Warehouse
	Sigecol	Significant Ecological Area	OMNR_LIO Warehouse
Niagara Escarpment	NEC_Export_Output	-	-
Oak Ridges Moraine	Orm_landform	Landform Conservation Areas	OMNR_LIO Warehouse
	Orm_landuse	Land Use Layer	OMNR_LIO Warehouse

Table 2-3: GIS Files Layers and Sources – Pre-defined Areas

Pre-defined Areas	Files Used	Description	Source
Private land	landown	Land Ownership	OMNR_LIO Warehouse
Crown land	landown	Land Ownership	OMNR_LIO Warehouse
First Nations	IRmay1205	First Nations Reserve	Ontario Ministry of Natural Resources

2.4 Constraints Analysis

A GIS analysis was performed to determine the constraints imposed on the land areas by cross-referencing GIS layers of information as per pre-established criteria. This was done based on Hélimax's professional experience while considering input from the OPA and MNR.

Constraints are defined as exclusion zones and, in certain cases, the buffer distances required from each of the exclusions. These are presented in the table below.[3]

Table 2-4: Constraints and Buffer Distances

Constraints	Suggested Buffer Distance
Hydrography (waterbody and watercourse)	100 m
Road	150 m
Railroad	150 m
Building	550 m
Waterway	1000 m
Slope	Not applicable
Provincial park	Not applicable
National park	Not applicable
Important Bird Area	Not applicable

As noted above, the constraints analysis does not include considerations related to local regulation, which would include issues such as zoning and land use planning. Nor does it address questions of social acceptability. The constraints analysis presented here only assesses the technical potential. The OPA would need to determine a coefficient to the technical potential to arrive at a value that would account for these other considerations.

2.5 Offshore Constraints

Due to technical and cost considerations, the offshore wind resource is only considered for water depths between 1 m and 25 m and at a distance of no more than 25 km from the coast. Important Bird Areas were also used as a constraint to evaluate offshore wind potential. A buffer distance of 1000 m was used for the waterway constraint layer.

Important constraints that were not available for this analysis include marinas, offshore areas set aside for oil and gas exploitation, and protected fishing areas. To compensate for this, Hélimax has included a coefficient of 0.6 to approximate the reduction in area considered accessible for development.

[3] Hélimax makes no guarantee with respect to the accuracy of the maps used for identifying or quantifying the land constraints.

2.6 Grid Interconnection Considerations

Distances to the distribution stations and transmission lines are also important considerations. For the purposes of this study, OPA requested that Hélimax evaluate proximity as follows:

- 5 km, 10 km, 15 km and 20 km from the Hydro One Networks' distribution stations;
- 10 km, 20 km, 50 km, 100 km and 300 km from transmission lines.

The technical potential for each of the pre-defined areas is presented relative to the distance to Hydro One Networks' transmission lines and distribution stations.

Normally, smaller generation facilities in the range of tens of megawatts to a few megawatts can be connected to a distribution system, whereas larger generation facilities in the range of hundreds of megawatts can be connected to a transmission system. The amount of generation that can realistically and cost effectively be connected to a transmission or distribution system at a point depends on a number of factors including:

- Distance between the point of connection and the generating facility;
- Voltage level of the transmission or distribution system (higher voltages mean larger generating facilities can be accommodated);
- Available capacity of the transmission or distribution system, both local and further upstream (indicates presence of other capacity users that may be load or generation);
- Electrical stiffness at the point of connection (indicator of the strength of the utility system – transmission and distribution system is weaker in remote areas);
- Impact on the other load and generation customers in the area;
- Nature of proposed generation (generation controls, etc.).

In addition to the above factors, the number of transmission/distribution facilities in an area determines the amount of generation that can be accommodated in that area.

There are far more single-phase distribution circuits than three-phase circuits in remote areas. However, three-phase circuits are required to connect generation facilities. The size of a generation facility that can be connected to a transmission or distribution system at a particular location requires a study considering the factors mentioned above.

Hydro One Networks is not the only transmitter or distributor in Ontario. For the purposes of this study, OPA considered Hydro One Networks data sufficient for the analysis because its transmission system covers almost the entire settled portion of Ontario except the Algoma District. Its distribution system covers most of rural Ontario, which, according to the constraints analysis, will be where wind generation can be located. A more complete analysis, especially for the eastern shore of Lake Superior, might be required to supplement the Hydro One Networks data.

Distances to the Hydro One Networks' distribution stations were considered because it is assumed that small amounts of wind generation can be connected to the nearest available distribution station. For local facility technical reasons, each location would need to be assessed individually by Hydro One Networks as part of a connection study.

Due to the preliminary nature of this analysis for the OPA, no consideration has been given to the voltages of transmission or distribution systems in the vicinity of the wind potential or the capacity of the systems in those areas to accommodate the wind generation. Additional work would be required to assess this.

3 RESULTS AND DISCUSSION

This section presents the results of the analyses. By overlaying constraints on the wind speed map published by the Ministry of Natural Resources (MNR) at a 1-kilometre resolution and at an elevation of 80 metres, Hélimax calculated the surface area showing wind speeds greater than 6.5 m/s that could potentially be developed.

Based on an estimate that 5 MW of wind can be installed per square kilometre, Hélimax has estimated the total MW capacity available for this wind speed class. Using an estimated average net capacity factor of 31% for this wind speed class, the total amount of energy in TWh available for wind power generation has been estimated.

Section 3.1 presents general province-wide results by detailing the total constrained potential for the entire province and a number of pre-defined provincial category areas within the province. Results for environmentally sensitive areas and offshore results are then presented, as well as a general overview of the constrained potential with respect to proximity to distribution stations and the transmission network.

Section 3.2 presents general results of the analysis for specific regions throughout the province.

Section 3.3 finishes with a detailed and comprehensive breakdown of the results at both a province-wide and regional scale.

In order to facilitate a quick understanding of the results, some important definitions and points will be reiterated here.

- The term "*unconstrained potential*" refers to the *raw onshore potential*.
- The term "*constrained potential*" excludes the potential in zones and buffer distance as defined in Table 2-4, but does not independently consider distance to grid.
- The term "*technical potential"* is the accessible wind resource within specified distances to either the distribution or transmission networks.

3.1 Section 1 – Province-wide Analysis

The following section will present constrained results for the entire province. OPA requested the selected province-wide categories based on its interest in broad indicators. Crown, private and First Nations lands were selected to give an indication of the respective potential roles in wind development.

Hélimax was also asked by the OPA to review the areas north and south of the 50th parallel as part of the province-wide analysis for reasons the OPA considered significant. The MNR wind atlas shows a significant proportion of wind potential in the far north of Ontario; this area is largely beyond the reach of the existing transmission system.

A map presented at the end of this section shows the 50th parallel and the transmission system.

3.1.1 Province-wide Constrained Onshore Analysis

The following tables summarize the constrained potential in MW capacity and associated terawatt-hours for the entire province, first as a function of geography and then as a function of land ownership. The potential within these areas is calculated by removing the following constraints: hydrography, road, railroads, slopes, buildings, national and provincial parks and important bird areas.

Table 3-1: Province-wide Analysis Results (Onshore)

Area	MW*	TWh**
Entire province	628,067	1711
North of 50th parallel	598,884	1632
South of 50th parallel	29,183	79

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)

Table 3-2: Province-wide Analysis by Land Ownership

Ownership	MW*	TWh**
Crown land	620,956	1692
Private land	4358	12
First Nations	2243	6

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)

Some interesting highlights of the analysis results are presented below.

- Total constrained onshore potential for the entire province of Ontario is 628,067 MW.
- 99% (620,956 MW) of the constrained potential for the entire province is on Crown land.
- 95% (598,884 MW) of the constrained potential in the entire province is north of the 50th parallel.

3.1.2 Environmentally Sensitive Areas Analysis

The following table details the constrained potential within environmentally sensitive areas. The potential within these areas is calculated by removing the following constraints: hydrography, road, railroads, slopes and buildings.

Please note that care should be exercised when interpreting these particular results as there is an unavoidable overlapping of zones within this part of the analysis. There is an overlap between Niagara Escarpment and Environmental Protected areas.

A map of the environmentally sensitive areas is presented below.

A more detailed breakdown of these results may be found in the distance matrices in Section 3.3.

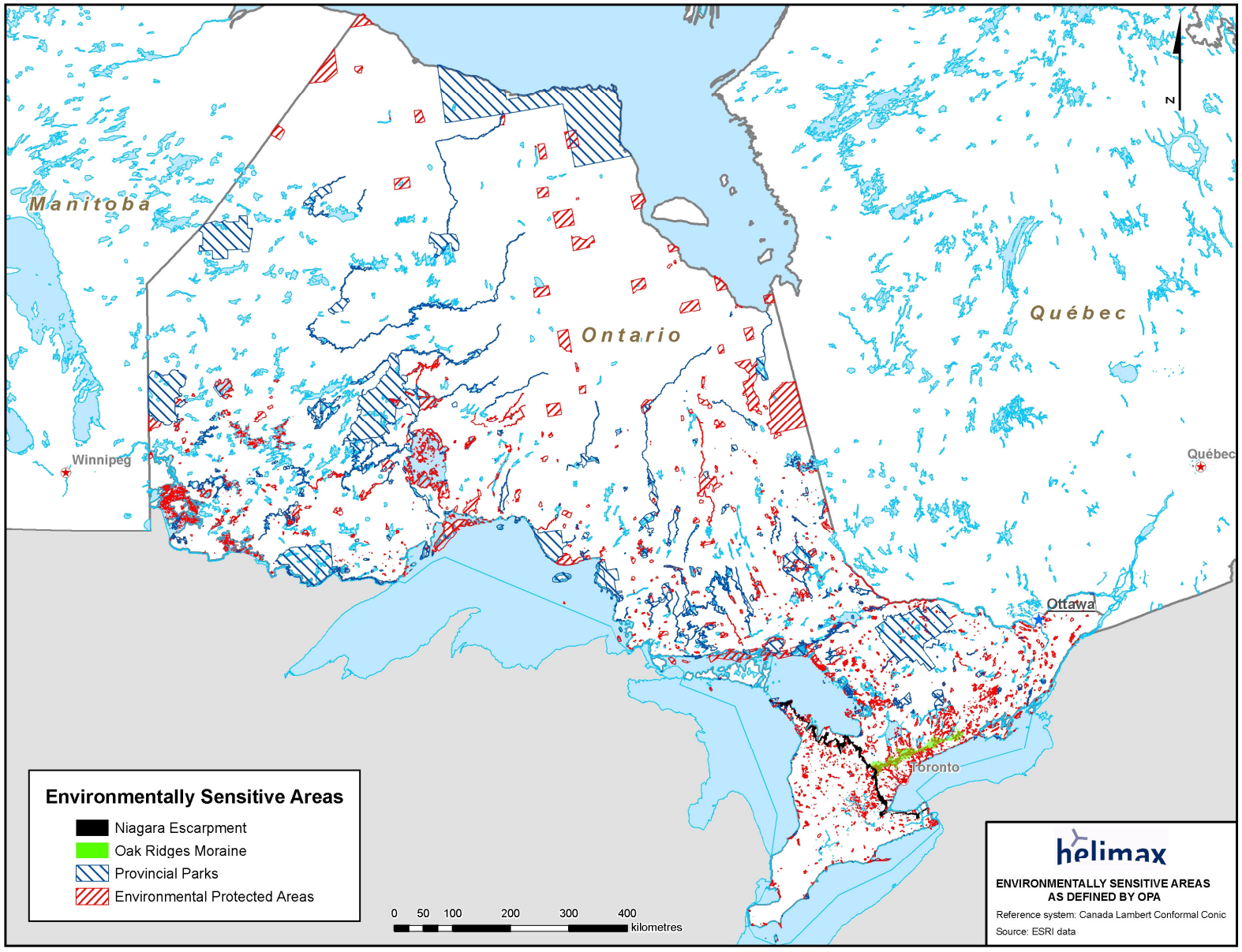
Table 3-3: Environmentally Sensitive Areas Analysis Results

Environmentally Sensitive Area*	MW**	TWh***
National and Provincial Parks	100,967	275
Environmental Protected Areas	38,540	105
Niagara Escarpment	1450	4
Oak Ridges Moraine	42	0

* some categories include overlapping

**assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)

*** assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)



Map 2: Environmentally Sensitive Areas of Ontario

3.1.3 Offshore Areas Analysis

The constrained offshore wind potential for the Great Lakes region of the province is presented below. The assumptions and calculation procedure for this analysis is presented in Section 2.5. It should be noted that the waters of James and Hudson's Bays fall under the jurisdiction of the territory of Nunavut, and were thus not considered in this analysis.

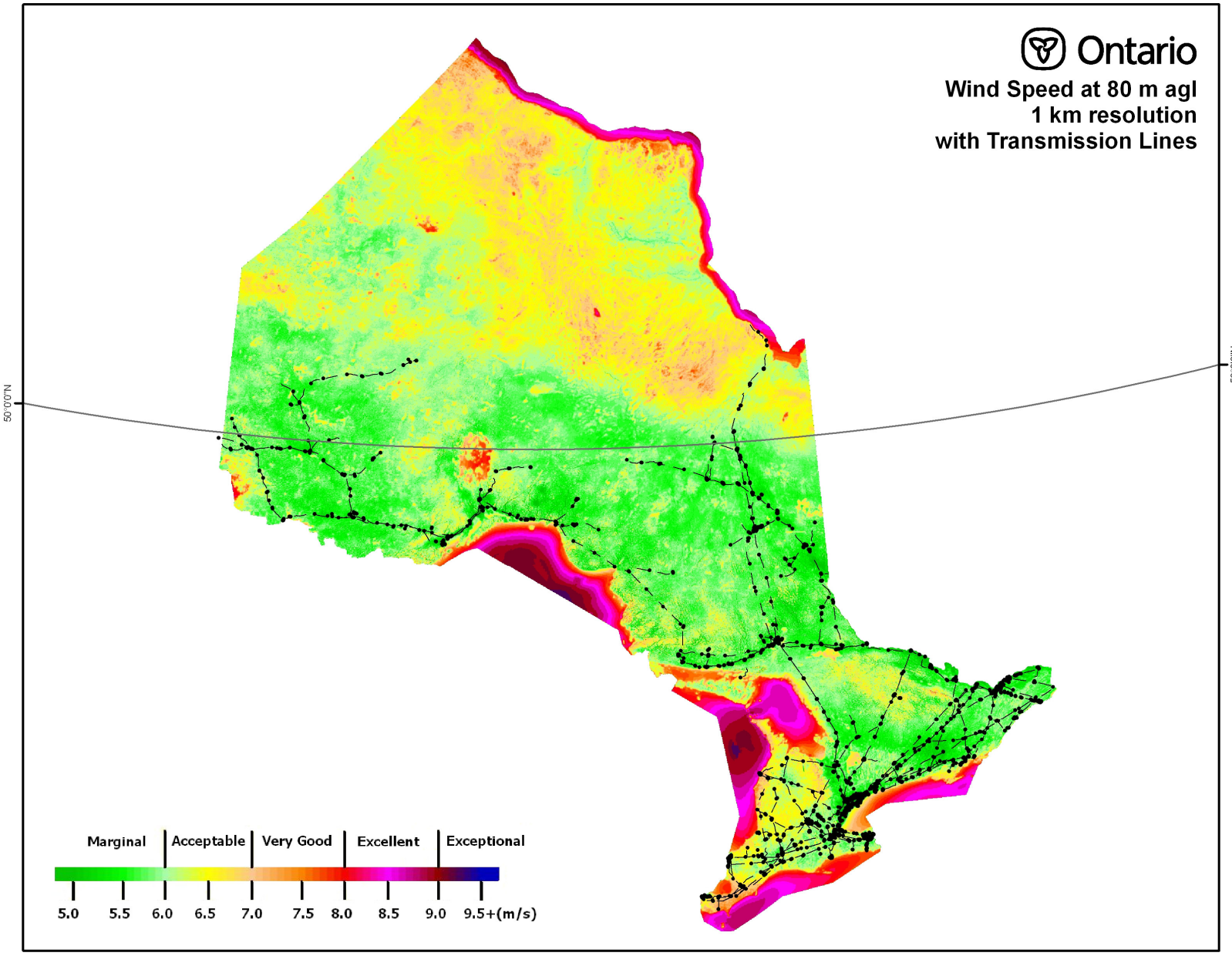
Table 3-4: Offshore Areas Analysis Results – Great Lakes Only

Offshore Area	MW*	TWh**
Lake Superior	2736	7
Lake Erie	21,054	57
Lake Huron Shore	20,439	56
Lake Ontario – North Shore	2599	7
Total Offshore (Great Lakes)	**46,827**	**128**

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)

Some noteworthy points from this analysis are:

- Considering both offshore (Great Lakes region) and onshore potential the entire province has a constrained potential of 674,894 MW.
- Lake Erie holds 45% of the total offshore resource, while Lake Huron Shore holds 44% of the total offshore resource for the Great Lakes region.



Map 3: Ontario Wind Speed Map with Transmission Lines

3.1.4 Province-wide Technical Potential Analysis

The "technical" potential is the constrained potential within specified distances to transmission lines or distribution stations. The results are presented in the tables below.

An element of caution must be exercised when reading these results as overlaps occur between areas that are in proximity to both the distribution and transmission networks. For a more complete breakdown, please refer to Section 3.3 where a distance matrix method is used to distinguish between areas of overlap.

Table 3-5: Province-wide Technical Potential – Transmission Network

	Potential after Constraints [MW]*	Within 300 km** [MW]	Within 100 km [MW]	Within 50 km [MW]	Within 20 km [MW]	Within 10 km [MW]
Entire Province	*628,067*	329,152	94,831	43,836	18,382	9317
North of 50th Parallel	*598,884*	299,970	65,828	21,453	5488	2497
South of 50th Parallel	*29,183*	29,182	29,003	22,383	12,894	6820

* Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.
** Distances are relative to nearest Transmission lines. Capacity on transmission lines necessary to integrate wind generation has not been considered. Additional work would be required.

Table 3-6: Province-wide Technical Potential - Distribution Network

	Potential after Constraints [MW]*	Within 20 km** [MW]	Within 15 km [MW]	Within 10 km [MW]	Within 5 km [MW]
Entire Province	628,067	13,460	11,311	7904	2964
North of 50th Parallel	598,884	29	16	0	0
South of 50th Parallel	29,183	13,431	11,295	7904	2964

* Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.
** Distances are relative to nearest Dx station. Capacity available at distribution stations necessary to integrate wind generation has not been considered. Additional work would be required.

Some interesting points from this analysis are:

- 15% (94,831 MW) of the constrained wind potential in the entire province is within 100 km of transmission lines.
- 11% (65,828 MW) of the constrained wind potential north of the 50th parallel is within 100 km of transmission lines.
- 70% (12,894 MW) of the constrained wind potential within 20 km of transmission lines is south of the 50th parallel.
- Significant amounts of constrained potential are within 10 km of transmission lines and 5 km of distribution stations.

3.2 Section 2 – Regional Analysis

The following section will present the results for specific regions and is intended to compliment the previous section. Results are presented in the same manner as above and the same methodology is used. The regions used for this analysis are:

- Bruce Peninsula
- Lake Erie – East
- Lake Erie – West
- Lake St. Clair
- Lake Ontario – North Shore
- Georgian Bay – South
- Georgian Bay – North
- Lake Huron Shore
- Lake Superior – North
- Lake Superior – South
- Central southwestern

See Map 4 at the end of this section for an illustration of these regions.

Note that an overlap will occur in certain regions where an area is within specified distances of both the transmission and distribution networks. Readers are directed to Section 3.3 where a more comprehensive breakdown of results can be found.

Table 3-7: Technical Potential for Pre-defined Areas - Transmission Network Only

	Potential after Constraints [MW]	Within 300 km* [MW]	Within 100 km [MW]	Within 50 km [MW]	Within 20 km [MW]	Within 10 km [MW]
Bruce Peninsula	1421	1421	1421	661	2	0
Lake Erie - East	50	50	50	50	41	18
Lake Erie - West	613	613	613	613	600	391
Lake St. Clair	470	470	470	470	470	412
Lake Ontario – North Shore	367	367	367	367	304	64
Georgian Bay - South	558	558	558	558	446	262
Georgian Bay - North	3410	3410	3410	2969	1178	420
Lake Huron Shore	1928	1928	1928	1928	1928	1670
Lake Superior - North	1094	1094	1094	1094	901	499
Lake Superior - South	3650	3650	3622	1199	271	94
Central Southwestern	1354	1354	1354	1354	1157	708
Total	**14,917**	**14,917**	**14,888**	**11,265**	**7296**	**4539**

* Distances are relative to nearest Tx lines. Capacity available on transmission lines or at distribution stations necessary to integrate wind generation has not been considered. Additional work would be required.

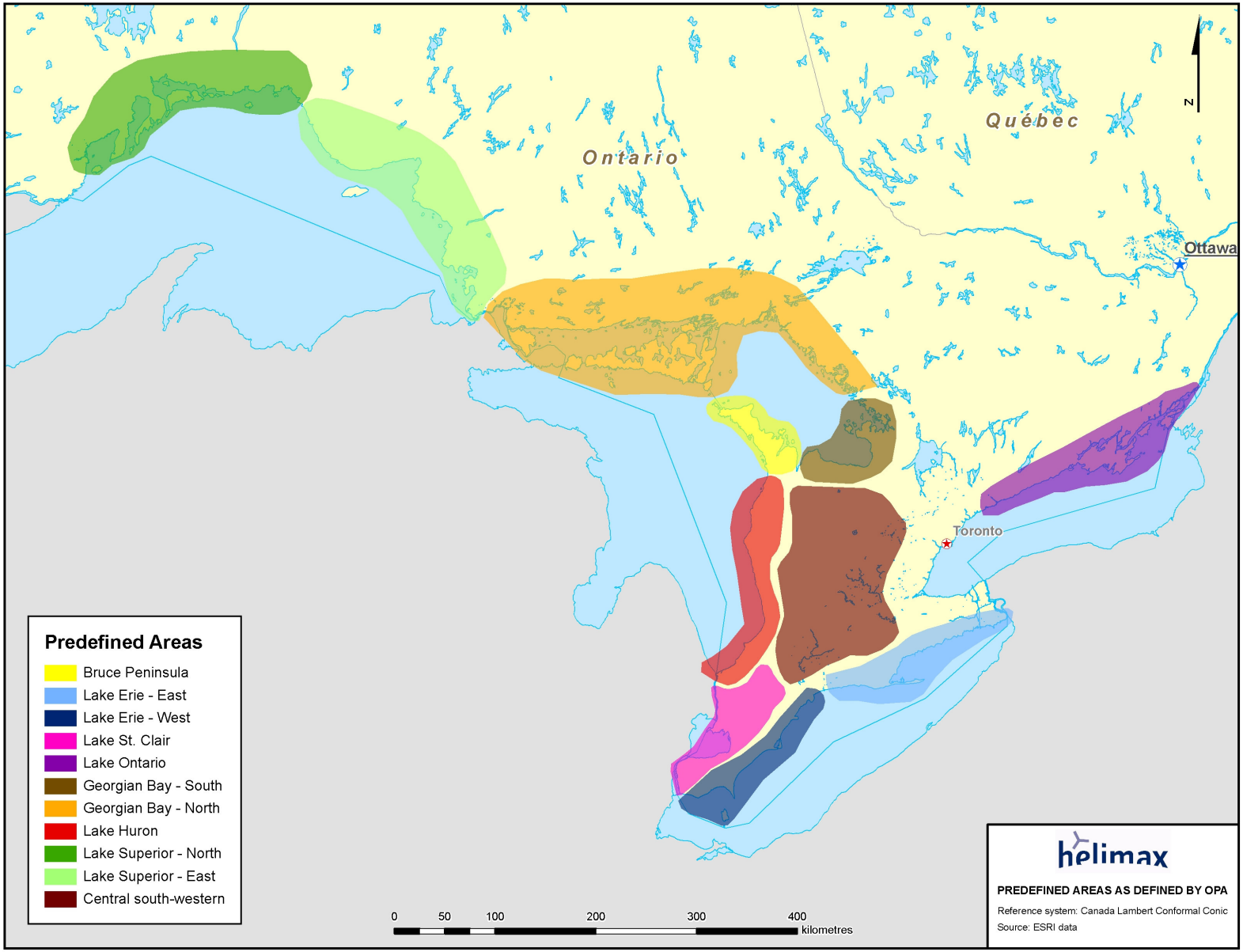
Table 3-8: Technical Potential for Pre-defined Areas - Distribution Network Only

	Potential after Constraints [MW]	Within 20 km* [MW]	Within 15 km [MW]	Within 10 km [MW]	Within 5 km [MW]
Bruce Peninsula	1421	1397	1234	766	232
Lake Erie – East	50	48	48	46	11
Lake Erie – West	613	613	613	565	264
Lake St. Clair	470	470	470	438	267
Lake Ontario – North Shore	367	364	364	354	185
Georgian Bay – South	558	558	510	334	113
Georgian Bay – North	3410	1097	734	389	75
Lake Huron Shore	1928	1928	1928	1649	728
Lake Superior – North	1094	256	127	50	17
Lake Superior – South	3650	6	0	0	0
Central Southwestern	1354	1354	1345	1220	618
Total	**14,917**	**8091**	**7373**	**5812**	**2510**

* Distances are relative to nearest Dx station. Capacity available on transmission lines or at distribution stations necessary to integrate wind generation has not been considered. Additional work would be required.

Some interesting points from this analysis are:

- 53% of the Bruce Peninsula technical potential is within 10 km of the distribution system;
- 16% (2510 MW) of the total MW capacity in these specific regions is within 5 km of the distribution network.



Map 4: Pre-defined Areas of Ontario

3.3 Section 3 - Comprehensive Results Including Distance Matrices

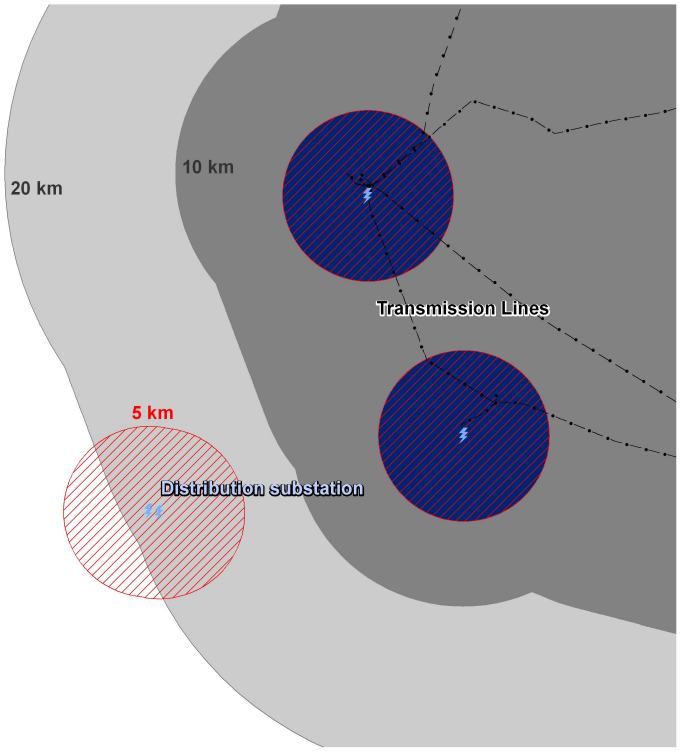
In this final section a detailed distance matrix method is used to give a thorough breakdown of results. In order to distinguish between areas which are in proximity to both the transmission lines and distribution stations, a “distance matrix” is used to present the results. This allows for an identification of the areas in which these “inclusion zones” overlap. A guide to reading the distance matrix is given in Section 3.3.1.

The reader is advised to review the following 3 examples to understand how the matrix displays information.

3.3.1 Guide to Reading Results Distance Matrix

The following examples demonstrate how to query or interpret values from the distance matrix. The distance matrix is a useful tool for distinguishing areas that may fall in the region of overlap between the distribution and transmission system, thus avoiding double counting of regions.

Example 1

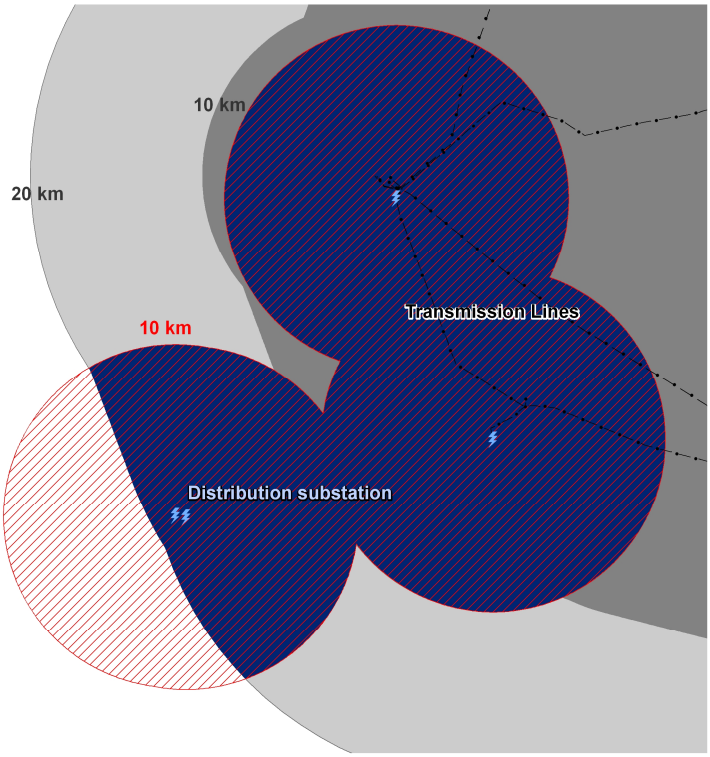


	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines
Within 5 km of Dx Station	2964	NA	NA	NA	1734	2480
Within 10 km of Dx Station	NA	7904	NA	NA	4111	6098
Within 15 km of Dx Station	NA	NA	11,311	NA	5013	8167
Within 20 km of Dx Station	NA	NA	NA	13,460	5460	9489
Within 10 km of Tx Lines	1734	4111	5013	5460	9317	NA
Within 20 km of Tx Lines	2480	6098	8167	9489	NA	18,382

The example above shows the region of intersection (in dark blue) that lies 5 km from the distribution system (in hatched red) **and** 10 km from the transmission system (dark grey). This value may be read from the table by following the row *"Within 5 km of Dx Station*" and the column "W*ithin 10 km of Transmission Lines*" leading to the value 1734 MW (highlighted in yellow). Equally, the same value may be ascertained by following the row "W*ithin 10 km of Transmission Lines*" until it meets the column "W*ithin 5 km of Dx Station,*" again giving the value of 1734 MW.

Example 2

The next example demonstrates a situation where there is an overlap (dark blue region) between a region that is both "W*ithin 10 km of Dx Station*" shown in hatched red and "W*ithin 20 km of Transmission Lines,"* shown here in light grey shading. The MW potential value for this region may be read by finding the intersection of the column "W*ithin 10 km of Dx Station"* with the row "W*ithin 20 km of Transmission Lines"* giving the value of 6098 MW (marked in the matrix in yellow). Likewise, the same value may be extracted by finding the intersection of the column *"Within 20 km of Transmission Lines'' with* the row "W*ithin 10 km of Dx Station"* to yield the same value: 6098 MW.

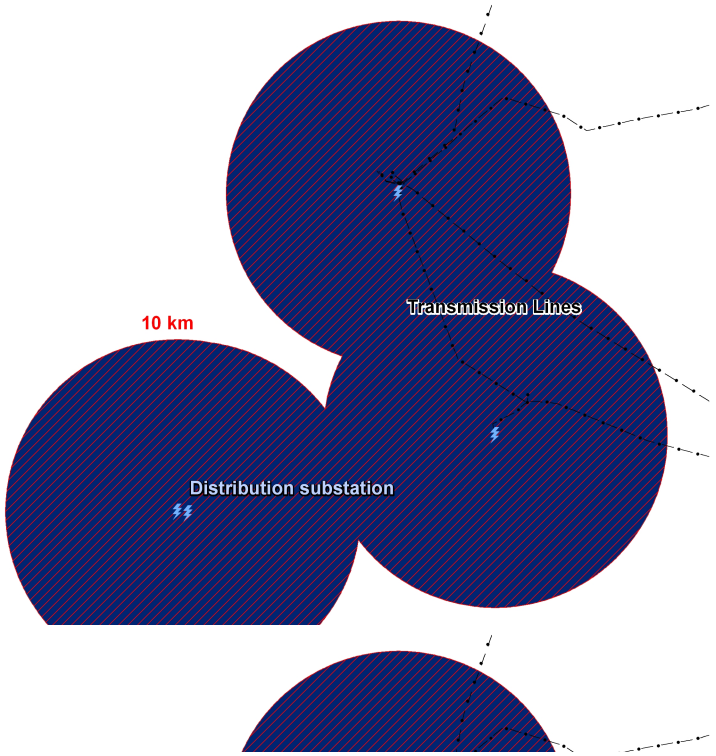


	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines
Within 5 km of Dx Station	2964	NA	NA	NA	1734	2480
Within 10 km of Dx Station	NA	7904	NA	NA	4111	6098
Within 15 km of Dx Station	NA	NA	11,311	NA	5013	8167
Within 20 km of Dx Station	NA	NA	NA	13,460	5460	9489
Within 10 km of Tx Lines	1734	4111	5013	5460	9317	NA
Within 20 km of Tx Lines	2480	6098	8167	9489	NA	18,382

Example 3

The final example shows a situation where there is no intersection between the distribution and transmission system. The region in dark blue highlights terrain that is 10 km from the distribution system. This value may be simply read for the matrix by finding the column and row marked *"Within 10 km of Dx Station"* to give the value 7904 MW (highlighted in yellow in the distance matrix below).

Note that in the distance matrix the diagonal will yield or give the value of a unique closed region with no intersection with other regions.



	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines
Within 5 km of Dx Station	2964	NA	NA	NA	1734	2480
Within 10 km of Dx Station	NA	7904	NA	NA	4111	6098
Within 15 km of Dx Station	NA	NA	11,311	NA	5013	8167
Within 20 km of Dx Station	NA	NA	NA	13,460	5460	9489
Within 10 km of Tx Lines	1734	4111	5013	5460	9317	NA
Within 20 km of Tx Lines	2480	6098	8167	9489	NA	18,382

Table 3-9: Technical Wind Potential for the Entire Province [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained **
Within 5 km of Dx Station	2964	NA	NA	NA	1734	2480	2804	2964	2964	NA	NA
Within 10 km of Dx Station	NA	7904	NA	NA	4111	6098	7445	7904	7904	NA	NA
Within 15 km of Dx Station	NA	NA	11,311	NA	5013	8167	10,448	11,311	11,311	NA	NA
Within 20 km of Dx Station	NA	NA	NA	13,460	5460	9489	12,348	13,460	13,460	NA	NA
Within 10 km of Tx Lines	1734	4111	5013	5460	9317	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	2480	6098	8167	9489	NA	18,382	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	2804	7445	10,448	12,348	NA	NA	43,836	NA	NA	NA	NA
Within 100 km of Tx Lines	2964	7904	11,311	13,460	NA	NA	NA	94,831	NA	NA	NA
Within 300 km of Tx Lines	2964	7904	11,311	13,460	NA	NA	NA	NA	329,152	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	1,063,145	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	628,067

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-10: Technical Wind Potential for the Entire Province [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained **
Within 5 km of Dx Station	8	NA	NA	NA	5	7	8	8	8	NA	NA
Within 10 km of Dx Station		22	NA	NA	11	17	20	22	22	NA	NA
Within 15 km of Dx Station	NA	NA	31	NA	14	22	28	31	31	NA	NA
Within 20 km of Dx Station	NA	NA	NA	37	15	26	34	37	37	NA	NA
Within 10 km of Tx Lines	5	11	14	15	25	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	7	17	22	26	NA	50	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	8	20	28	34	NA	NA	119	NA	NA	NA	NA
Within 100 km of Tx Lines	8	22	31	37	NA	NA	NA	258	NA	NA	NA
Within 300 km of Tx Lines	8	22	31	37	NA	NA	NA	NA	897	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	2896	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1711

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-11: Technical Wind Potential for North of the 50th Parallel [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained **
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	0	NA	NA	0	0	0	0	0	NA	NA
Within 15 km of Dx Station	NA	NA	16	NA	4	15	16	16	16	NA	NA
Within 20 km of Dx Station	NA	NA	NA	29	4	27	29	29	29	NA	NA
Within 10 km of Tx Lines	0	0	4	4	2497	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	0	15	27	NA	5488	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	0	16	29	NA	NA	21,453	NA	NA	NA	NA
Within 100 km of Tx Lines	0	0	16	29	NA	NA	NA	65,828	NA	NA	NA
Within 300 km of Tx Lines	0	0	16	29	NA	NA	NA	NA	299,970	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	905,057	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	598,884

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-12: Technical Wind Potential for North of the 50th Parallel [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	0	NA	NA	0	0	0	0	0	NA	NA
Within 15 km of Dx Station	NA	NA	0	NA	0	0	0	0	0	NA	NA
Within 20 km of Dx Station	NA	NA	NA	0	0	0	0	0	0	NA	NA
Within 10 km of Tx Lines	0	0	0	0	7	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	0	0	0	NA	15	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	0	0	0	NA	NA	58	NA	NA	NA	NA
Within 100 km of Tx Lines	0	0	0	0	NA	NA	NA	179	NA	NA	NA
Within 300 km of Tx Lines	0	0	0	0	NA	NA	NA	NA	817	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	2466	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1632

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-13: Technical Wind Potential for Crown Land [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	2173	NA	NA	NA	1220	1777	2013	2173	2173	NA	NA
Within 10 km of Dx Station	NA	5389	NA	NA	2898	4005	4991	5389	5389	NA	NA
Within 15 km of Dx Station	NA	NA	7875	NA	3656	5466	7115	7875	7875	NA	NA
Within 20 km of Dx Station	NA	NA	NA	9508	4006	6528	8530	9508	9508	NA	NA
Within 10 km of Tx Lines	1220	2898	3656	4006	7735	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	1777	4005	5466	6528	NA	14,955	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	2013	4991	7115	8530	NA	NA	38,501	NA	NA	NA	NA
Within 100 km of Tx Lines	2173	5389	7875	9508	NA	NA	NA	87,832	NA	NA	NA
Within 300 km of Tx Lines	2173	5389	7875	9508	NA	NA	NA	NA	322,056	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	1,030,953	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	620,956

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-14: Technical Wind Potential for Crown Land [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	6	NA	NA	NA	3	5	5	6	6	NA	NA
Within 10 km of Dx Station	NA	15	NA	NA	8	11	14	15	15	NA	NA
Within 15 km of Dx Station	NA	NA	21	NA	10	15	19	21	21	NA	NA
Within 20 km of Dx Station	NA	NA	NA	26	11	18	23	26	26	NA	NA
Within 10 km of Tx Lines	3	8	10	11	21	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	5	11	15	18	NA	41	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	5	14	19	23	NA	NA	105	NA	NA	NA	NA
Within 100 km of Tx Lines	6	15	21	26	NA	NA	NA	239	NA	NA	NA
Within 300 km of Tx Lines	6	15	21	26	NA	NA	NA	NA	877	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	2809	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1692

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-15: Technical Wind Potential for Private Land [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	739	NA	NA	NA	508	655	739	739	739	NA	NA
Within 10 km of Dx Station	NA	1901	NA	NA	1165	1609	1887	1901	1901	NA	NA
Within 15 km of Dx Station	NA	NA	2316	NA	1305	1820	2259	2316	2316	NA	NA
Within 20 km of Dx Station	NA	NA	NA	2587	1336	1940	2500	2587	2587	NA	NA
Within 10 km of Tx Lines	508	1165	1305	1336	1357	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	655	1609	1820	1940	NA	2125	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	739	1887	2259	2500	NA	NA	3190	NA	NA	NA	NA
Within 100 km of Tx Lines	739	1901	2316	2587	NA	NA	NA	4357	NA	NA	NA
Within 300 km of Tx Lines	739	1901	2316	2587	NA	NA	NA	NA	4358	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	23,626	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	4358

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-16: Technical Wind Potential for Private Land [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	2	NA	NA	NA	1	2	2	2	2	NA	NA
Within 10 km of Dx Station	NA	5	NA	NA	3	4	5	5	5	NA	NA
Within 15 km of Dx Station	NA	NA	6	NA	4	5	6	6	6	NA	NA
Within 20 km of Dx Station	NA	NA	NA	7	4	5	7	7	7	NA	NA
Within 10 km of Tx Lines	1	3	4	4	4	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	2	4	5	5	NA	6	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	2	5	6	7	NA	NA	9	NA	NA	NA	NA
Within 100 km of Tx Lines	2	5	6	7	NA	NA	NA	12	NA	NA	NA
Within 300 km of Tx Lines	2	5	6	7	NA	NA	NA	NA	12	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	64	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	12

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-17: Technical Wind Potential for First Nations [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	7	NA	NA	NA	2	4	7	7	7	NA	NA
Within 10 km of Dx Station	NA	97	NA	NA	20	29	51	97	97	NA	NA
Within 15 km of Dx Station	NA	NA	195	NA	21	59	148	195	195	NA	NA
Within 20 km of Dx Station	NA	NA	NA	371	53	99	325	371	371	NA	NA
Within 10 km of Tx Lines	2	20	21	53	71	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	4	29	59	99	NA	186	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	7	51	148	325	NA	NA	783	NA	NA	NA	NA
Within 100 km of Tx Lines	7	97	195	371	NA	NA	NA	967	NA	NA	NA
Within 300 km of Tx Lines	7	97	195	371	NA	NA	NA	NA	2198	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	5329	NA
Constrained* **	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2243

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-18: Technical Wind Potential for First Nations [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	0	NA	NA	0	0	0	0	0	NA	NA
Within 15 km of Dx Station	NA	NA	1	NA	0	0	0	1	1	NA	NA
Within 20 km of Dx Station	NA	NA	NA	1	0	0	1	1	1	NA	NA
Within 10 km of Tx Lines	0	0	0	0	0	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	0	0	0	NA	1	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	0	0	1	NA	NA	2	NA	NA	NA	NA
Within 100 km of Tx Lines	0	0	1	1	NA	NA	NA	3	NA	NA	NA
Within 300 km of Tx Lines	0	0	1	1	NA	NA	NA	NA	6	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	15	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	6

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-19: Technical Wind Potential for Bruce Peninsula [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	232	NA	NA	NA	0	1	81	232	232	NA	NA
Within 10 km of Dx Station	NA	766	NA	NA	0	2	356	766	766	NA	NA
Within 15 km of Dx Station	NA	NA	1234	NA	0	2	576	1234	1234	NA	NA
Within 20 km of Dx Station	NA	NA	NA	1397	0	2	637	1397	1397	NA	NA
Within 10 km of Tx Lines	0	0	0	0	0	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	1	2	2	2	NA	2	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	81	356	576	637	NA	NA	661	NA	NA	NA	NA
Within 100 km of Tx Lines	232	766	1234	1397	NA	NA	NA	1421	NA	NA	NA
Within 300 km of Tx Lines	232	766	1234	1397	NA	NA	NA	NA	1421	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	6626	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1421

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-20: Technical Wind Potential for Bruce Peninsula [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	1	NA	NA	NA	0	0	0	1	1	NA	NA
Within 10 km of Dx Station	NA	2	NA	NA	0	0	1	2	2	NA	NA
Within 15 km of Dx Station	NA	NA	3	NA	0	0	2	3	3	NA	NA
Within 20 km of Dx Station	NA	NA	NA	4	0	0	2	4	4	NA	NA
Within 10 km of Tx Lines	0	0	0	0	0	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	0	0	0	NA	0	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	1	2	2	NA	NA	2	NA	NA	NA	NA
Within 100 km of Tx Lines	1	2	3	4	NA	NA	NA	4	NA	NA	NA
Within 300 km of Tx Lines	1	2	3	4	NA	NA	NA	NA	4	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	18	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	4

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-21: Technical Wind Potential for Lake Erie - East [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	11	NA	NA	NA	6	9	11	11	11	NA	NA
Within 10 km of Dx Station	NA	46	NA	NA	15	37	46	46	46	NA	NA
Within 15 km of Dx Station	NA	NA	48	NA	16	38	48	48	48	NA	NA
Within 20 km of Dx Station	NA	NA	NA	48	17	38	48	48	48	NA	NA
Within 10 km of Tx Lines	6	15	16	17	18	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	9	37	38	38	NA	41	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	11	46	48	48	NA	NA	50	NA	NA	NA	NA
Within 100 km of Tx Lines	11	46	48	48	NA	NA	NA	50	NA	NA	NA
Within 300 km of Tx Lines	11	46	48	48	NA	NA	NA	NA	50	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	1987	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	50

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-22: Technical Wind Potential for Lake Erie - East [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	0	NA	NA	0	0	0	0	0	NA	NA
Within 15 km of Dx Station	NA	NA	0	NA	0	0	0	0	0	NA	NA
Within 20 km of Dx Station	NA	NA	NA	0	0	0	0	0	0	NA	NA
Within 10 km of Tx Lines	0	0	0	0	0	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	0	0	0	NA	0	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	0	0	0	NA	NA	0	NA	NA	NA	NA
Within 100 km of Tx Lines	0	0	0	0	NA	NA	NA	0	NA	NA	NA
Within 300 km of Tx Lines	0	0	0	0	NA	NA	NA	NA	0	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	5	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-23: Technical Wind Potential for Lake Erie - West [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	264	NA	NA	NA	176	259	264	264	264	NA	NA
Within 10 km of Dx Station	NA	565	NA	NA	383	551	565	565	565	NA	NA
Within 15 km of Dx Station	NA	NA	613	NA	391	600	613	613	613	NA	NA
Within 20 km of Dx Station	NA	NA	NA	613	391	600	613	613	613	NA	NA
Within 10 km of Tx Lines	176	383	391	391	391	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	259	551	600	600	NA	600	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	264	565	613	613	NA	NA	613	NA	NA	NA	NA
Within 100 km of Tx Lines	264	565	613	613	NA	NA	NA	613	NA	NA	NA
Within 300 km of Tx Lines	264	565	613	613	NA	NA	NA	NA	613	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	9692	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	613

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-24: Technical Wind Potential for Lake Erie - West [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	1	NA	NA	NA	0	1	1	1	1	NA	NA
Within 10 km of Dx Station	NA	2	NA	NA	1	2	2	2	2	NA	NA
Within 15 km of Dx Station	NA	NA	2	NA	1	2	2	2	2	NA	NA
Within 20 km of Dx Station	NA	NA	NA	2	1	2	2	2	2	NA	NA
Within 10 km of Tx Lines	0	1	1	1	1	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	1	2	2	2	NA	2	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	1	2	2	2	NA	NA	2	NA	NA	NA	NA
Within 100 km of Tx Lines	1	2	2	2	NA	NA	NA	2	NA	NA	NA
Within 300 km of Tx Lines	1	2	2	2	NA	NA	NA	NA	2	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	26	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-25: Technical Wind Potential for Lake St. Clair [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	267	NA	NA	NA	238	267	267	267	267	NA	NA
Within 10 km of Dx Station	NA	438	NA	NA	402	438	438	438	438	NA	NA
Within 15 km of Dx Station	NA	NA	470	NA	412	470	470	470	470	NA	NA
Within 20 km of Dx Station	NA	NA	NA	470	412	470	470	470	470	NA	NA
Within 10 km of Tx Lines	238	402	412	412	412	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	267	438	470	470	NA	470	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	267	438	470	470	NA	NA	470	NA	NA	NA	NA
Within 100 km of Tx Lines	267	438	470	470	NA	NA	NA	470	NA	NA	NA
Within 300 km of Tx Lines	267	438	470	470	NA	NA	NA	NA	470	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	9776	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	470

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-26: Technical Wind Potential for Lake St. Clair [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	1	NA	NA	NA	1	1	1	1	1	NA	NA
Within 10 km of Dx Station	NA	1	NA	NA	1	1	1	1	1	NA	NA
Within 15 km of Dx Station	NA	NA	1	NA	1	1	1	1	1	NA	NA
Within 20 km of Dx Station	NA	NA	NA	1	1	1	1	1	1	NA	NA
Within 10 km of Tx Lines	1	1	1	1	1	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	1	1	1	1	NA	1	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	1	1	1	1	NA	NA	1	NA	NA	NA	NA
Within 100 km of Tx Lines	1	1	1	1	NA	NA	NA	1	NA	NA	NA
Within 300 km of Tx Lines	1	1	1	1	NA	NA	NA	NA	1	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	27	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-27: Technical Wind Potential for Lake Ontario – North Shore [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	185	NA	NA	NA	41	177	185	185	185	NA	NA
Within 10 km of Dx Station	NA	354	NA	NA	64	297	354	354	354	NA	NA
Within 15 km of Dx Station	NA	NA	364	NA	64	304	364	364	364	NA	NA
Within 20 km of Dx Station	NA	NA	NA	364	64	304	364	364	364	NA	NA
Within 10 km of Tx Lines	41	64	64	64	64	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	177	297	304	304	NA	304	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	185	354	364	364	NA	NA	367	NA	NA	NA	NA
Within 100 km of Tx Lines	185	354	364	364	NA	NA	NA	367	NA	NA	NA
Within 300 km of Tx Lines	185	354	364	364	NA	NA	NA	NA	367	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	5174	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	367

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-28: Technical Wind Potential for Lake Ontario – North Shore [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	1	NA	NA	NA	0	0	1	1	1	NA	NA
Within 10 km of Dx Station	NA	1	NA	NA	0	1	1	1	1	NA	NA
Within 15 km of Dx Station	NA	NA	1	NA	0	1	1	1	1	NA	NA
Within 20 km of Dx Station	NA	NA	NA	1	0	1	1	1	1	NA	NA
Within 10 km of Tx Lines	0	0	0	0	0	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	1	1	1	NA	1	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	1	1	1	1	NA	NA	1	NA	NA	NA	NA
Within 100 km of Tx Lines	1	1	1	1	NA	NA	NA	1	NA	NA	NA
Within 300 km of Tx Lines	1	1	1	1	NA	NA	NA	NA	1	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	14	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-29: Technical Wind Potential for Georgian Bay - South [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	113	NA	NA	NA	100	108	113	113	113	NA	NA
Within 10 km of Dx Station	NA	334	NA	NA	243	313	334	334	334	NA	NA
Within 15 km of Dx Station	NA	NA	510	NA	262	438	510	510	510	NA	NA
Within 20 km of Dx Station	NA	NA	NA	558	262	445	558	558	558	NA	NA
Within 10 km of Tx Lines	100	243	262	262	262	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	108	313	438	445	NA	446	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	113	334	510	558	NA	NA	558	NA	NA	NA	NA
Within 100 km of Tx Lines	113	334	510	558	NA	NA	NA	558	NA	NA	NA
Within 300 km of Tx Lines	113	334	510	558	NA	NA	NA	NA	558	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	3853	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	558

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-30: Technical Wind Potential for Georgian Bay - South [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	1	NA	NA	1	1	1	1	1	NA	NA
Within 15 km of Dx Station	NA	NA	1	NA	1	1	1	1	1	NA	NA
Within 20 km of Dx Station	NA	NA	NA	2	1	1	2	2	2	NA	NA
Within 10 km of Tx Lines	0	1	1	1	1	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	1	1	1	NA	1	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	1	1	2	NA	NA	2	NA	NA	NA	NA
Within 100 km of Tx Lines	0	1	1	2	NA	NA	NA	2	NA	NA	NA
Within 300 km of Tx Lines	0	1	1	2	NA	NA	NA	NA	2	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	10	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-31: Technical Wind Potential for Georgian Bay - North [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	75	NA	NA	NA	37	65	73	75	75	NA	NA
Within 10 km of Dx Station	NA	389	NA	NA	186	262	382	389	389	NA	NA
Within 15 km of Dx Station	NA	NA	734	NA	220	435	720	734	734	NA	NA
Within 20 km of Dx Station	NA	NA	NA	1097	275	648	1083	1097	1097	NA	NA
Within 10 km of Tx Lines	37	186	220	275	420	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	65	262	435	648	NA	1178	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	73	382	720	1083	NA	NA	2969	NA	NA	NA	NA
Within 100 km of Tx Lines	75	389	734	1097	NA	NA	NA	3410	NA	NA	NA
Within 300 km of Tx Lines	75	389	734	1097	NA	NA	NA	NA	3410	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	11,455	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	3410

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-32: Technical Wind Potential for Georgian Bay - North [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	1	NA	NA	1	1	1	1	1	NA	NA
Within 15 km of Dx Station	NA	NA	2	NA	1	1	2	2	2	NA	NA
Within 20 km of Dx Station	NA	NA	NA	3	1	2	3	3	3	NA	NA
Within 10 km of Tx Lines	0	1	1	1	1	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	1	1	2	NA	3	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	1	2	3	NA	NA	8	NA	NA	NA	NA
Within 100 km of Tx Lines	0	1	2	3	NA	NA	NA	9	NA	NA	NA
Within 300 km of Tx Lines	0	1	2	3	NA	NA	NA	NA	9	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	31	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-33: Technical Wind Potential for Lake Huron Shore [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	728	NA	NA	NA	547	728	728	728	728	NA	NA
Within 10 km of Dx Station	NA	1 649	NA	NA	1408	1649	1649	1649	1649	NA	NA
Within 15 km of Dx Station	NA	NA	1928	NA	1670	1928	1928	1928	1928	NA	NA
Within 20 km of Dx Station	NA	NA	NA	1928	1670	1928	1928	1928	1928	NA	NA
Within 10 km of Tx Lines	547	1408	1670	1670	1670	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	728	1649	1928	1928	NA	1928	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	728	1649	1928	1928	NA	NA	1928	NA	NA	NA	NA
Within 100 km of Tx Lines	728	1649	1928	1928	NA	NA	NA	1928	NA	NA	NA
Within 300 km of Tx Lines	728	1649	1928	1928	NA	NA	NA	NA	1928	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	13,917	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1928

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-34: Technical Wind Potential for Lake Huron Shore [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	2	NA	NA	NA	1	2	2	2	2	NA	NA
Within 10 km of Dx Station	NA	4	NA	NA	4	4	4	4	4	NA	NA
Within 15 km of Dx Station	NA	NA	5	NA	5	5	5	5	5	NA	NA
Within 20 km of Dx Station	NA	NA	NA	5	5	5	5	5	5	NA	NA
Within 10 km of Tx Lines	1	4	5	5	5	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	2	4	5	5	NA	5	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	2	4	5	5	NA	NA	5	NA	NA	NA	NA
Within 100 km of Tx Lines	2	4	5	5	NA	NA	NA	5	NA	NA	NA
Within 300 km of Tx Lines	2	4	5	5	NA	NA	NA	NA	5	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	38	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-35: Technical Wind Potential for Lake Superior - North [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	17	NA	NA	NA	17	17	17	17	17	NA	NA
Within 10 km of Dx Station	NA	50	NA	NA	50	50	50	50	50	NA	NA
Within 15 km of Dx Station	NA	NA	127	NA	125	127	127	127	127	NA	NA
Within 20 km of Dx Station	NA	NA	NA	256	225	256	256	256	256	NA	NA
Within 10 km of Tx Lines	17	50	125	225	499	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	17	50	127	256	NA	901	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	17	50	127	256	NA	NA	1094	NA	NA	NA	NA
Within 100 km of Tx Lines	17	50	127	256	NA	NA	NA	1094	NA	NA	NA
Within 300 km of Tx Lines	17	50	127	256	NA	NA	NA	NA	1094	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	2151	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1094

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-36: Technical Wind Potential for Lake Superior - North [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	0	NA	NA	0	0	0	0	0	NA	NA
Within 15 km of Dx Station	NA	NA	0	NA	0	0	0	0	0	NA	NA
Within 20 km of Dx Station	NA	NA	NA	1	1	1	1	1	1	NA	NA
Within 10 km of Tx Lines	0	0	0	1	1	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	0	0	1	NA	2	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	0	0	1	NA	NA	3	NA	NA	NA	NA
Within 100 km of Tx Lines	0	0	0	1	NA	NA	NA	3	NA	NA	NA
Within 300 km of Tx Lines	0	0	0	1	NA	NA	NA	NA	3	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	6	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	3

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-37: Technical Wind Potential for Lake Superior - East [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	0	NA	NA	0	0	0	0	0	NA	NA
Within 15 km of Dx Station	NA	NA	0	NA	0	0	0	0	0	NA	NA
Within 20 km of Dx Station	NA	NA	NA	6	6	6	6	6	6	NA	NA
Within 10 km of Tx Lines	0	0	0	6	94	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	0	0	6	NA	271	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	0	0	6	NA	NA	1199	NA	NA	NA	NA
Within 100 km of Tx Lines	0	0	0	6	NA	NA	NA	3622	NA	NA	NA
Within 300 km of Tx Lines	0	0	0	6	NA	NA	NA	NA	3650	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	9080	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	3650

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-38: Technical Wind Potential for Lake Superior - East [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	0	NA	NA	NA	0	0	0	0	0	NA	NA
Within 10 km of Dx Station	NA	0	NA	NA	0	0	0	0	0	NA	NA
Within 15 km of Dx Station	NA	NA	0	NA	0	0	0	0	0	NA	NA
Within 20 km of Dx Station	NA	NA	NA	0	0	0	0	0	0	NA	NA
Within 10 km of Tx Lines	0	0	0	0	0	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	0	0	0	0	NA	1	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	0	0	0	0	NA	NA	3	NA	NA	NA	NA
Within 100 km of Tx Lines	0	0	0	0	NA	NA	NA	10	NA	NA	NA
Within 300 km of Tx Lines	0	0	0	0	NA	NA	NA	NA	10	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	25	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	10

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-39: Technical Wind Potential Central Southwestern Ontario [MW]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	618	NA	NA	NA	347	543	618	618	618	NA	NA
Within 10 km of Dx Station	NA	1220	NA	NA	657	1065	1220	1220	1220	NA	NA
Within 15 km of Dx Station	NA	NA	1345	NA	698	1148	1345	1345	1345	NA	NA
Within 20 km of Dx Station	NA	NA	NA	1354	708	1157	1354	1354	1354	NA	NA
Within 10 km of Tx Lines	347	657	698	708	708	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	543	1065	1148	1157	NA	1157	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	618	1220	1345	1354	NA	NA	1354	NA	NA	NA	NA
Within 100 km of Tx Lines	618	1220	1345	1354	NA	NA	NA	1354	NA	NA	NA
Within 300 km of Tx Lines	618	1220	1345	1354	NA	NA	NA	NA	1354	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	15,084	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1354

* assumes 5 MW of capacity per suitable km^2 of area with average wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.

Table 3-40: Technical Wind Potential for Central Southwestern Ontario [TWh]*

	Within 5 km of Dx Station	Within 10 km of Dx Station	Within 15 km of Dx Station	Within 20 km of Dx Station	Within 10 km of Tx Lines	Within 20 km of Tx Lines	Within 50 km of Tx Lines	Within 100 km of Tx Lines	Within 300 km of Tx Lines	Unconstrained	Constrained**
Within 5 km of Dx Station	2	NA	NA	NA	1	1	2	2	2	NA	NA
Within 10 km of Dx Station	NA	3	NA	NA	2	3	3	3	3	NA	NA
Within 15 km of Dx Station	NA	NA	4	NA	2	3	4	4	4	NA	NA
Within 20 km of Dx Station	NA	NA	NA	4	2	3	4	4	4	NA	NA
Within 10 km of Tx Lines	1	2	2	2	2	NA	NA	NA	NA	NA	NA
Within 20 km of Tx Lines	1	3	3	3	NA	3	NA	NA	NA	NA	NA
Within 50 km of Tx Lines	2	3	4	4	NA	NA	4	NA	NA	NA	NA
Within 100 km of Tx Lines	2	3	4	4	NA	NA	NA	4	NA	NA	NA
Within 300 km of Tx Lines	2	3	4	4	NA	NA	NA	NA	4	NA	NA
Unconstrained	NA	NA	NA	NA	NA	NA	NA	NA	NA	41	NA
Constrained**	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	4

* assumes 31.1% average net capacity factor for sites with wind speeds exceeding 6.5 m/s at 80 m agl (as per 1-km MNR mesoscale map)
** Constraints include hydrography, roads, railroads, slopes, houses, provincial parks, national parks and Important Bird Areas only.